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INNOVATION OUTLOOK

RENEWABLE METHANOL

in partnership with

METHANOL INSTITUTE

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About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future and serves as the principal platform for international co-operation, a centre of excellence and a repository of policy, technology, resource and financial knowledge on renewable energy. IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy, in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity. **www.irena.org**

About METHANOL INSTITUTE

The Methanol Institute (MI) is the global trade association for the methanol industry, representing the world's leading producers, distributors, and technology companies. Founded in 1989 in Washington DC, MI now represents its members from five offices around world in Washington DC, Beijing, Brussels, Delhi, and Singapore. MI serves its members as the voice of the methanol industry, representing companies within the membership to governments and businesses around the world to promote the sustainable growth of the industry. MI focuses on advancing the utilisation of methanol as a clean fuel in energy-related applications such as land & marine transport, power generation, fuel cells, industrial boilers, and cook stoves. MI also supports sustainable and renewable process to produce methanol as a carbon-neutral chemical and fuel. **www.methanol.org**

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KEY FINDINGS

Methanol plays an important role in the chemical industry, and is an emerging energy fuel currently mostly produced from fossil fuels. A transition to renewable methanol – derived from biomass or synthesised from green hydrogen and carbon dioxide (CO_2) – could expand methanol's use as a chemical feedstock and fuel while moving industrial and transport sectors toward net carbon neutral goals. The cost of renewable methanol production is currently high and production volumes are low. But with the right policies, renewable methanol could be cost-competitive by 2050 or earlier.

1. Methanol:

- Methanol is a key product in the chemical industry. It is mainly used for producing other chemicals such as formaldehyde, acetic acid and plastics. Around 98 million tonnes (Mt) are produced per annum, nearly all of which is produced from fossil fuels (either natural gas or coal).
- The life-cycle emissions from current methanol production and use are around 0.3 gigatonnes (Gt) CO_2 per annum (about 10% of total chemical sector emissions).
- Methanol production has nearly doubled in the past decade, with a large share of that growth being in China. Under current trends, production could rise to 500 Mt per annum by 2050, releasing 1.5 Gt CO_2 per annum if solely sourced from fossil fuels.
- The cost of producing fossil fuel-based methanol is in the range of USD 100-250 per tonne (t).

2. Renewable methanol:

- Renewable methanol can be produced using renewable energy and renewable feedstocks via two routes:
    - Bio-methanol is produced from biomass. Key potential sustainable biomass feedstocks include: forestry and agricultural waste and by-products, biogas from landfill, sewage, municipal solid waste (MSW) and black liquor from the pulp and paper industry.
    - Green e-methanol is obtained by using CO_2 captured from renewable sources (bioenergy with carbon capture and storage [BECCS] and direct air capture [DAC]) and green hydrogen, i.e. hydrogen produced with renewable electricity.
- Less than 0.2 Mt of renewable methanol is produced annually, mostly as bio-methanol. The methanol produced by either route is chemically identical to methanol produced from fossil fuel sources.
- Interest in renewable methanol is being driven by the need to mitigate climate change by substantially reducing or eliminating CO_2 emissions, and in particular by the growing focus on holding the average global temperature rise to no more than 1.5°C. This implies achieving net carbon neutral emissions across all sectors of the economy by mid-century.
- Low-emission methanol could play a larger role in decarbonising certain sectors where options are currently limited – particularly as a feedstock in the chemical industry or as a fuel in road or marine transport.

3. Production costs of bio-methanol:

- Since production is currently low, limited data are available on actual costs, meaning that potential costs need to be estimated. The bio-methanol production cost will depend on the bio-feedstock cost, investment cost and the efficiency of the conversion processes.

Biomass and MSW feedstock costs vary between USD 0 and USD 17 per gigajoule (GJ).

- With a lower feedstock cost range of up to USD 6/GJ, the cost of bio-methanol is estimated to be in the range USD 320/t and USD 770/t, with the range influenced by differences in the specific projects – including differences in CAPEX, OPEX and conversion efficiency.
- With process improvements, the cost range could be reduced to between USD 220/t and USD 560/t for the lower feedstock price range up to 6 USD/GJ, with a correspondingly higher range for the higher feedstock price range.
- Production of bio-methanol from the waste streams of other industrial processes (e.g. black liquor from paper mills and MSW) in particular offer opportunities to simplify the feedstock logistics and improve overall plant economics. Co-production of heat, electricity or other chemicals could also potentially improve the economics of bio-methanol production.
- In the short term biomass could be co-fed into a coal-based gasifier, or biogas fed into a natural gas-based methanol plant, so allowing for the gradual introduction of biomass as a feedstock and making methanol production more sustainable at a potentially lower cost.

4. Production costs of green e-methanol:

- The cost of e-methanol depends to a large extent on the cost of hydrogen and CO_2. The cost of CO_2 depends on the source from which it is captured, e.g. from biomass, industrial processes or DAC.
- The current production cost of e-methanol is estimated to be in the range USD 800-1 600/t assuming CO_2 is sourced from BECCS at a cost of USD 10-50/t. If CO_2 is obtained by DAC, where costs are currently USD 300-600/t, then e-methanol production costs would be in the range USD 1 200-2 400/t.
- The future cost of green hydrogen production mainly depends on the combination of further reductions in the cost of renewable power generation and electrolysers, and gains in efficiency and durability.
- With anticipated decreases in renewable power prices, the cost of e-methanol is expected to decrease to levels between USD 250-630/t by 2050.
- As in the case of bio-methanol, co-production of brown/grey (fossil) and green e-methanol could allow the gradual introduction of green e-methanol at a reasonable cost.

5. Benefits and challenges for renewable methanol:

- Renewable methanol can be produced from a variety of sustainable feedstocks, such as biomass, waste or CO_2 and hydrogen. Its use in place of fossil fuels can reduce greenhouse gas (GHG) emissions and in some cases can also reduce other harmful emissions (sulphur oxides [SOx], nitrogen oxides [NOx], particulate matter [PM] etc.)
- It is a versatile fuel that can be used in internal combustion engines, and in hybrid and fuel cell vehicles and vessels. It is a liquid at ambient temperature and pressures, and so is straightforward to store, transport and distribute. It is compatible with existing distribution infrastructure and can be blended with conventional fuels.
- Production of methanol from biomass and from CO_2 and H_2 does not involve experimental technologies. Almost identical proven and fully commercial technologies are used to make methanol from fossil fuel-based syngas and can be used for bio- and e-methanol production.
- Currently the main barrier to renewable methanol uptake is its higher cost compared to fossil fuel-based alternatives, and that cost differential will persist for some time to come. However, its value is in its emission reduction potential compared to existing options.
- Addressing process differences and facilitating the scale-up of production and use can help reduce costs, but will require a variety of policy interventions. With the right support mechanisms, and with the best production conditions, renewable methanol could approach the current cost and price of methanol from fossil fuels.

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ABBREVIATIONS

AGR	Acid gas removal
ASU	Air separation unit
BECCS	Bioenergy with carbon capture and storage
BECCU	Bioenergy with carbon capture and use
BEV	Battery electric vehicle
BTX	Benzene, toluene and xylenes (aromatics)
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CCU	Carbon capture and use
CFD	Contract for difference
CH_3OH	Methanol
CI	Carbon intensity
CNG	Compressed natural gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2-eq	Carbon dioxide equivalent
COS	Carbonyl sulphide
CPP	Coal power plant
CRI	Carbon Recycling International
DAC	Direct air capture
DME	Dimethyl ether
DMFC	Direct methanol fuel cell
DWT	Deadweight tonnage
ECA	Emission Control Areas
e-fuel	Electrofuel
EU	European Union
EV	Electric vehicle
FCV	Fuel cell vehicle
FEED	Front-end engineering design
FFV	Flexible fuel vehicle
FT fuels	Fischer-Tropsch fuels
GHG	Greenhouse gas
H_2	Hydrogen
HCl	Hydrogen chloride
HF	Hydrogen fluoride
HF	Hydrogen fluoride
HHV	Higher heating value
ICE	Internal combustion engine
IMO	International Maritime Organization
IRR	Internal rate of return
LCA	Life-cycle analysis
LCFS	Low Carbon Fuel Standard
LCM	Low-carbon methanol
LHV	Lower heating value
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MDI	Methylenebis (4-phenyl isocyanate)
MMA	Methyl methacrylate
MSW	Municipal solid waste
MTBE	methyl tert-butyl ether
MTG	Methanol-to-gasoline
MTO	Methanol-to-olefins
NOx	Nitrogen oxides
n/k	Not known
OMEs	Oxymethylene ethers
OPEX	Operating expenditure
PEM	Polymer electrolyte membrane
PM	Particulate matter
PV	Photovoltaic
RED	Renewable Energy Directive
RES	Renewable energy source
SGAB	Sub Group on Advanced Biofuels
SNG	Synthetic natural gas
SOx	Sulphur oxides
TRL	Technology readiness level
TTW	Tank-to-wheel
US	United States
WGS	Water gas shift
WTT	Wheel-to-tank
WTW	Wheel-to-wheel

UNITS OF MEASURE

EJ	Exajoule
GJ	Gigajoule
Gt	Gigatonne
kg	Kilogram
km	Kilometre
kt/y	Thousand tonnes per year
kW	Kilowatt
kWh	Kilowatt hour
L	Litre
L/d	Litres per day
MJ	Megajoule
Mt	Million tonnes
$MtCO_2$	Million tonnes of carbon dioxide
MW	Megawatt
MWh	Megawatt hour
MW_t	Megawatt thermal
m^3	Cubic metre
t	Tonne
t/d	Tonnes per day
t/y	Tonnes per year

SUMMARY FOR POLICY MAKERS

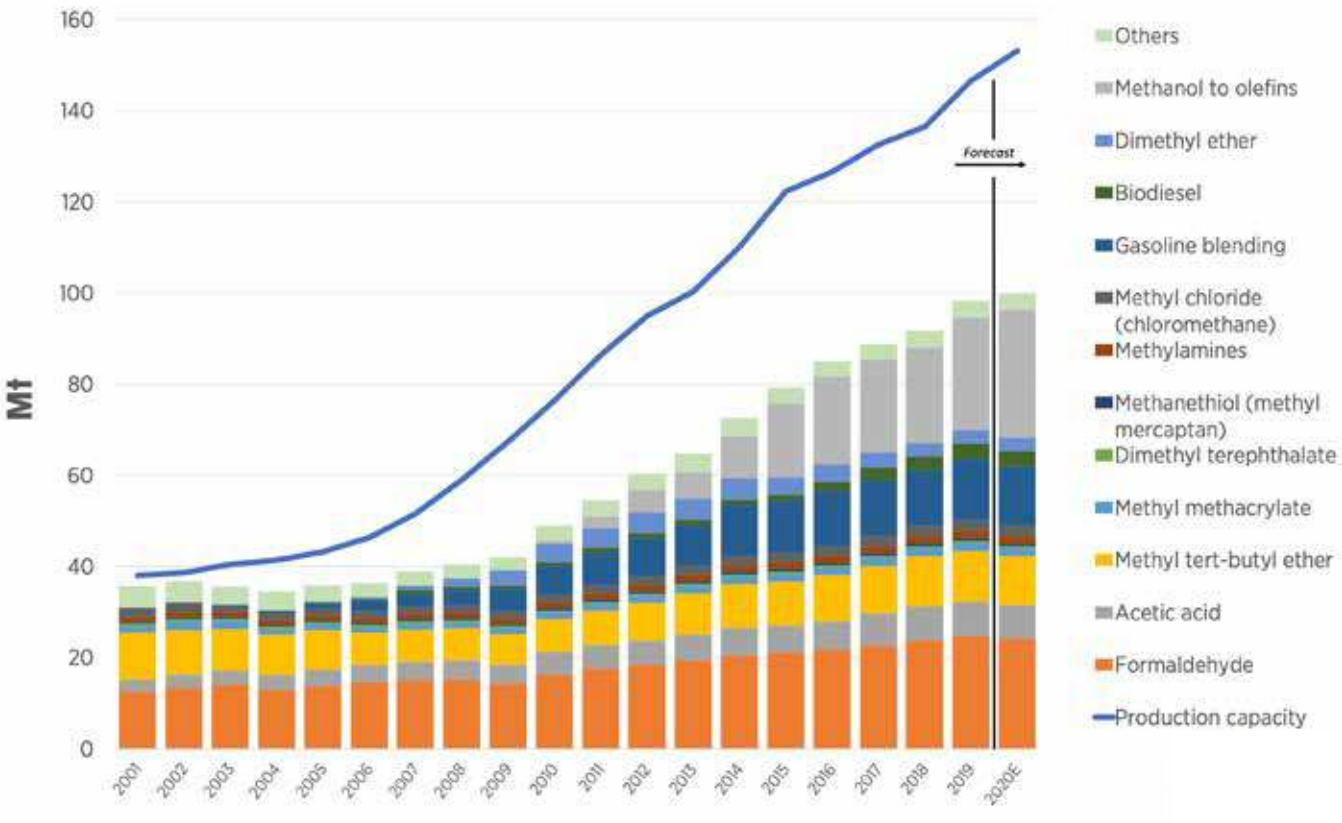
Methanol is one of the four critical basic chemicals – alongside ethylene, propylene and ammonia – used to produce all other chemical products. About two-thirds of methanol is used to produce other chemicals, such as formaldehyde, acetic acid and plastics. Methanol use for the production of polyethylene and polypropylene in particular has grown significantly, going from almost zero ten years ago to 25 Mt in 2019. The remaining methanol is mainly used as a fuel for vehicles, ships, industrial boilers and cooking. Methanol's use as a fuel – either by itself, as a blend with gasoline, for the production of biodiesel, or in the form of methyl *tert*-butyl ether (MTBE) and dimethyl ether (DME) – has also grown rapidly since the mid-2000s.

Most methanol is currently produced from natural gas or coal, with estimated annual life-cycle emissions of 0.3 Gt CO_2, around 10% of the total chemical and petrochemical sector's CO_2 emissions. Addressing emissions from methanol production is therefore a key component of the decarbonisation of the chemical sector and could contribute to the transport sector where the methanol can be used as a fuel.

Market status and production process

Worldwide annual production of methanol nearly doubled over the past decade to reach about 98 Mt in 2019. A large part of that growth came from China through methanol production from coal. Methanol demand is expected to continue increasing to reach more than 120 Mt by 2025 (MMSA, 2020; Berggren, 2019) and 500 Mt by 2050 in IRENA's Transforming Energy Scenario.

Figure 1. Global methanol demand and production capacity (2001-2019)



Source: *Based on data from MMSA (2020).*

This is in line with the "well-below 2°C" Paris climate goal (Saygin and Gielen, forthcoming). Most of the growth until 2028 is expected to come from the Chinese market, mainly to be used in the production of olefins, with a smaller share for gasoline blending, formaldehyde, acetic acid and MTBE production.

Renewable methanol

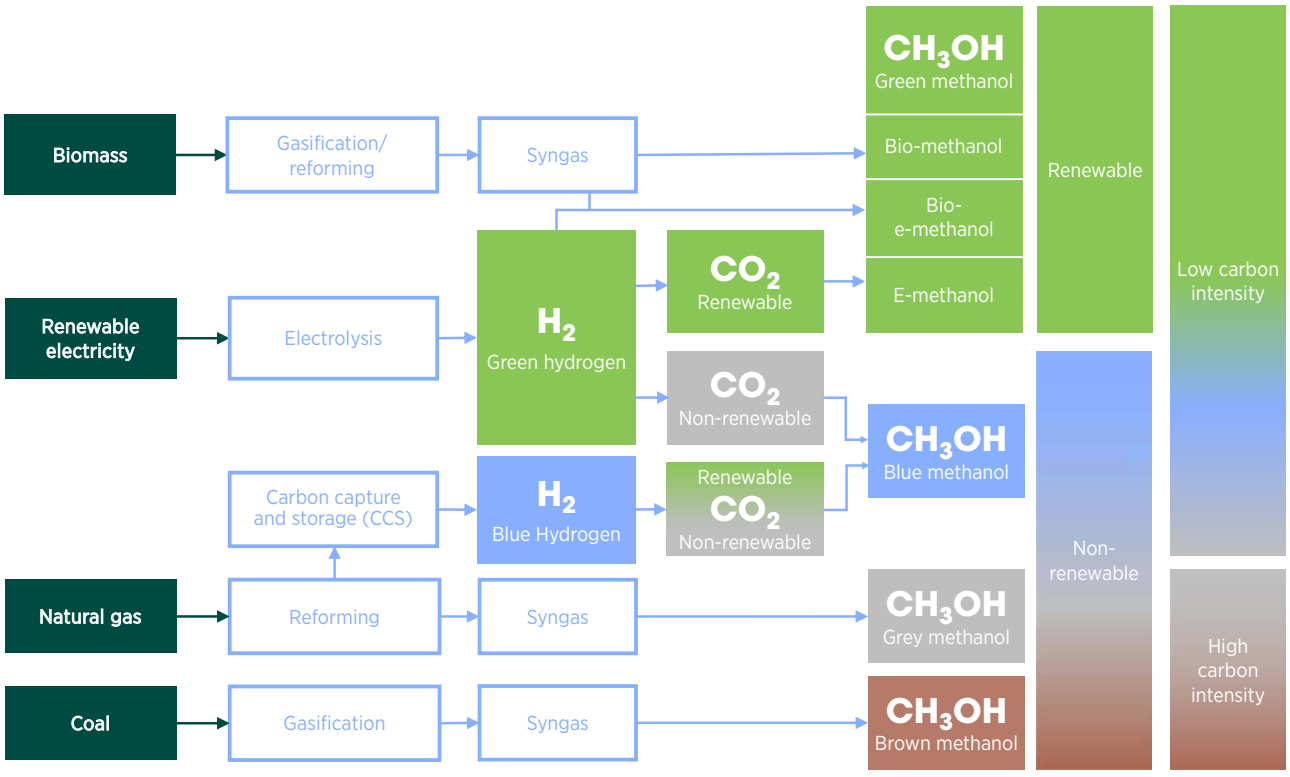
Currently, methanol is produced almost exclusively from fossil fuels. However, methanol can also be made from other feedstocks that contain carbon, including biomass, biogas, waste streams and CO_2 (for example captured from flue gases or through DAC).

Renewable methanol can be produced using renewable energy and renewable feedstocks via two routes:

- Bio-methanol is produced from biomass. Key potential sustainable biomass feedstocks include: forestry and agricultural waste and by-products, biogas from landfill, sewage, MSW and black liquor from the pulp and paper industry.
- Green e-methanol is obtained from CO_2 captured from renewable sources (e.g. via BECCS or DAC) and green hydrogen, i.e. hydrogen produced with renewable electricity.

To qualify as renewable, all feedstocks and energy used to produce the methanol need to be of renewable origin (e.g. biomass, solar, wind, hydro, geothermal). The methanol produced by either route is chemically identical to methanol produced from fossil fuel sources.

Figure 2. Principal methanol production routes



Renewable CO_2: *from bio-origin and through direct air capture (DAC)*

Non-renewable CO_2: *from fossil origin, industry*

While there is not a standard colour code for the different types of methanol production processes; this illustration of various types of methanol according to feedstock and energy sources is an initial proposition that is meant to be a basis for further discussion with stakeholders

Current progress on renewable methanol production

Less than 0.2 Mt of renewable methanol is produced annually, from only a handful of plants. Those renewable-methanol commercial facilities and demonstration projects focus mainly on using waste and by-product streams from other industrial processes, which offer the best economics at present. Suitable feedstocks include: MSW and low-priced biomass, biogas, waste streams, and black liquor from the pulp and paper industry.

For example, a commercial-scale plant producing bio-methanol from bio-methane is in operation in the Netherlands and a plant producing bio-methanol from MSW is operating in Canada. In Iceland, e-methanol is produced by combining renewable hydrogen and CO_2 from a geothermal power plant. The current projects benefit from favourable conditions, such as low feedstock cost (e.g. biogas), strong integration with conventional industrial processes (e.g. pulp and paper industry), or very inexpensive renewable electricity (e.g. geothermal and hydro energy in Iceland). Depending on appropriate local conditions, there are other early or niche opportunities for bio-methanol and e-methanol production (e.g. integrated production with bio-ethanol from sugarcane, co-feeding biomass feedstock and fossil fuels, and co-production of heat, electricity and other chemicals).

The co-feeding of renewable feedstock (e.g. biomass, CO_2, green hydrogen, renewable electricity) into natural gas- or coal-based methanol production facilities could be a strategy to gradually introduce renewable methanol production, and reduce the environmental impact and carbon intensity of conventional methanol production. The output of these hybrid plants is sometimes called low-carbon methanol (LCM). This demand could help with the early scale-up of electrolysers for hydrogen production, CO_2 capture processes and other technologies for later large-scale renewable methanol deployment.

Cost competitiveness of renewable methanol

Renewable methanol production costs are significantly higher than those of today's natural gas- and coal-based methanol production (whose production costs are in the range of USD 100-250/t). With the lowest-cost feedstocks and with improvements in production processes, the cost of producing renewable methanol from either the gasification of biomass or MSW, or using CO_2 and renewable hydrogen, could approach the current cost and price of methanol from fossil fuels, as illustrated in Figure 3 and Figure 4.

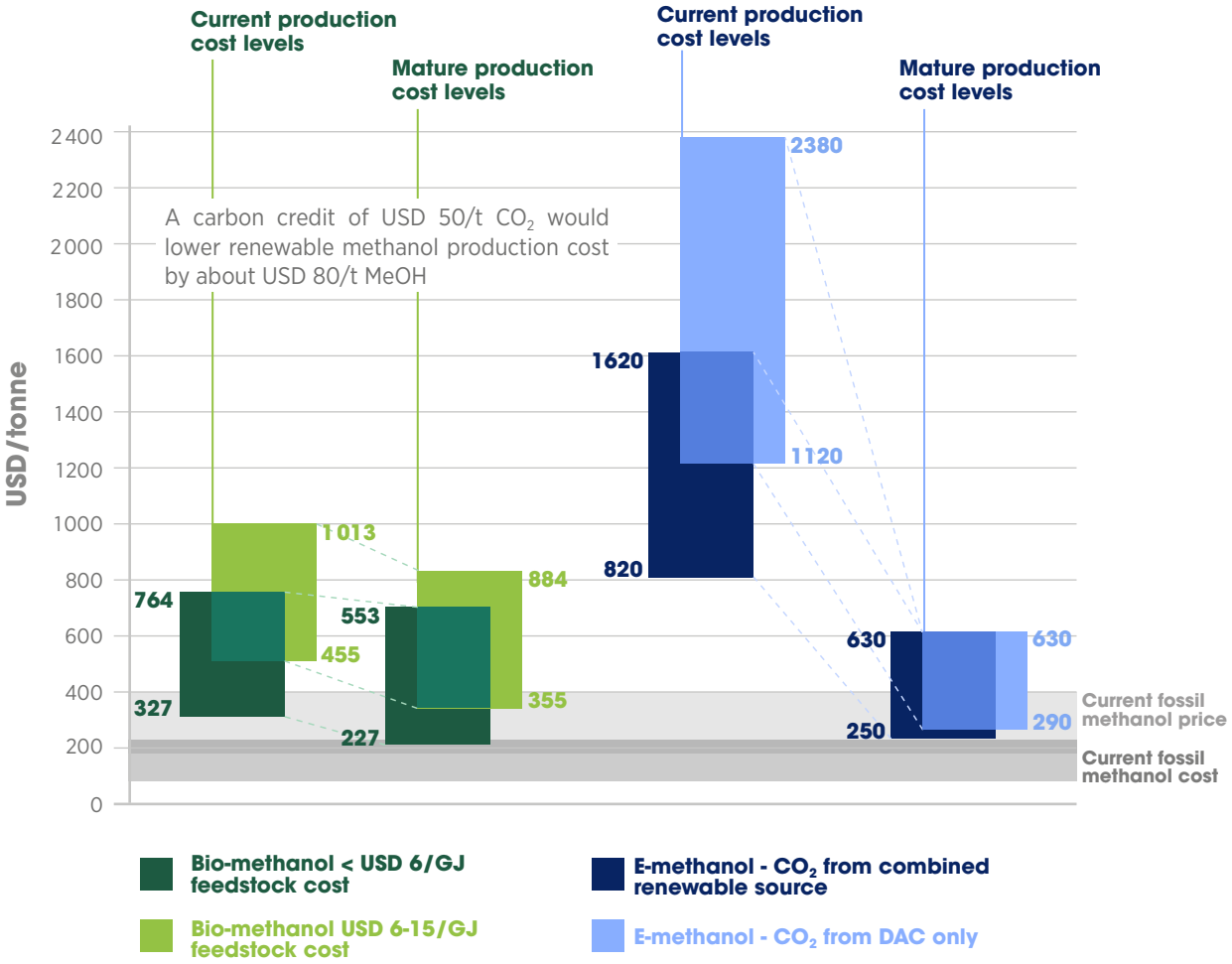
Improving the competitiveness of bio-methanol

Technology maturity and cost reduction. The gasification of oil and coal is a well-proven technology with multiple large units in operation. The application of gasification technologies to various biomass types and MSW is, however, in the early commercialisation phase and requires further development before reaching full commercial status. In the optimum cases, bio-methanol is close to competing on cost with fossil fuel-generated methanol, but it is more expensive, in many cases, by a factor of up to two. As the cost of the feedstock is not expected to decrease significantly in the future, reducing CAPEX will be the largest contributor to lowering production costs, through economies of scale and learning curve mechanisms such as process improvements, improved and more (cost-) effective plant configurations and plant size.

Sustainable and low-cost biomass feedstocks. The scale-up of bio-methanol production will depend on the availability of low-cost biomass feedstock (the share of feedstock cost in the total production cost can be as high as 50%). Bio-methanol production requires reliable and consistent supplies of feedstock. While in some cases biomass feedstock supplies can be provided locally, many other projects require more extensive supply chains.

The biomass must be sustainably sourced. Sustainability assessments and monitoring are needed to consider and manage the risks of adverse economic, environmental and social impacts (IRENA, 2020a). The gross maximum availability of sustainable biomass in the world is estimated to be 147 exajoules in 2030 (IRENA, 2014). Biomass feedstock costs around the world can vary by up to 17 USD/GJ depending on the type and the location. The lowest-cost feedstocks – i.e. below USD 6/GJ (EUR 20/megawatt hour) are mainly MSW and residues, and the availability of these feedstocks is limited. As biomass has the potential for use in a wide range of options for energy purposes and for materials, bio-methanol production will be competing with other applications.

Figure 3. Current and future production costs of bio- and e-methanol



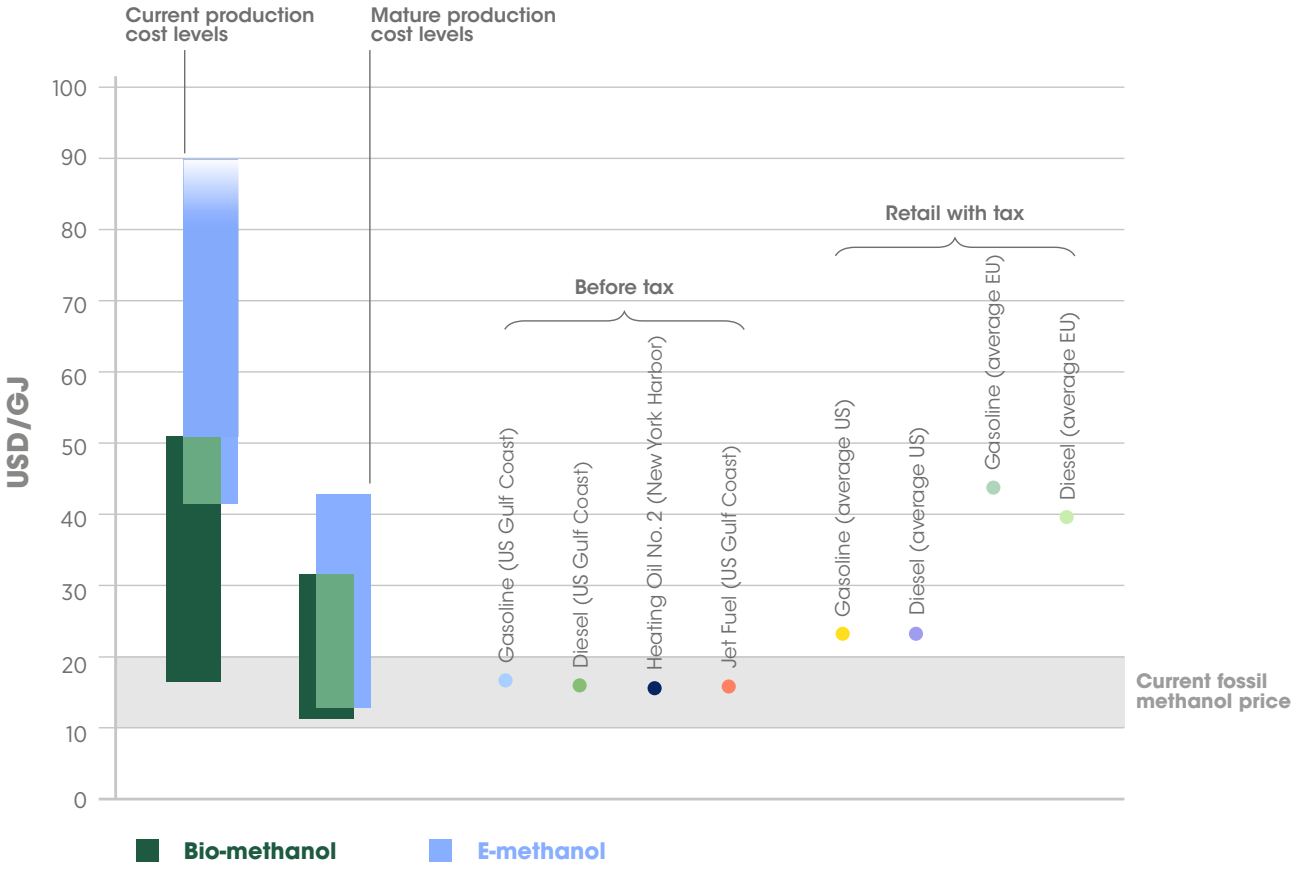
Notes: *MeOH = methanol. Costs do not incorporate any carbon credit that might be available. Current fossil methanol cost and price are from coal and natural gas feedstock in 2020. Exchange rate used in this figure is USD 1 = EUR 0.9.*

Improving the competitiveness of e-methanol

Abundant and low-cost green hydrogen. Large-scale production of e-methanol will depend on the availability of inexpensive green hydrogen and CO_2, as well as the capital cost of the plant. From a cost perspective the main drivers will be the cost of the renewable power needed to generate the required H_2, as well as plant utilisation rates (especially the electrolysers). Currently, e-methanol remains costly to produce from these sources. However, the cost of renewable electricity produced from wind and solar, which is already competitive with fossil fuel-generated electricity in most markets, is predicted to continue decreasing over the next decades (IRENA, 2020b; IRENA, 2020c). The cost of e-methanol should therefore also decrease significantly over the same period. Economies of scale and innovation in electrolysers will also help reduce costs.

A sustainable and affordable source of carbon. The necessary CO_2 can be captured from various sources including power plants and industrial exhaust streams (e.g. iron, steel and cement production). However, to be renewable and sustainable, CO_2 has to be obtained

Figure 4. Comparison of renewable methanol with other fuels on a price per unit of energy basis



Notes: *Exchange rate used in this figure USD 1 = EUR 0.9. Fuel costs and prices are averaged over 10 years. See Annex 3 for details.*

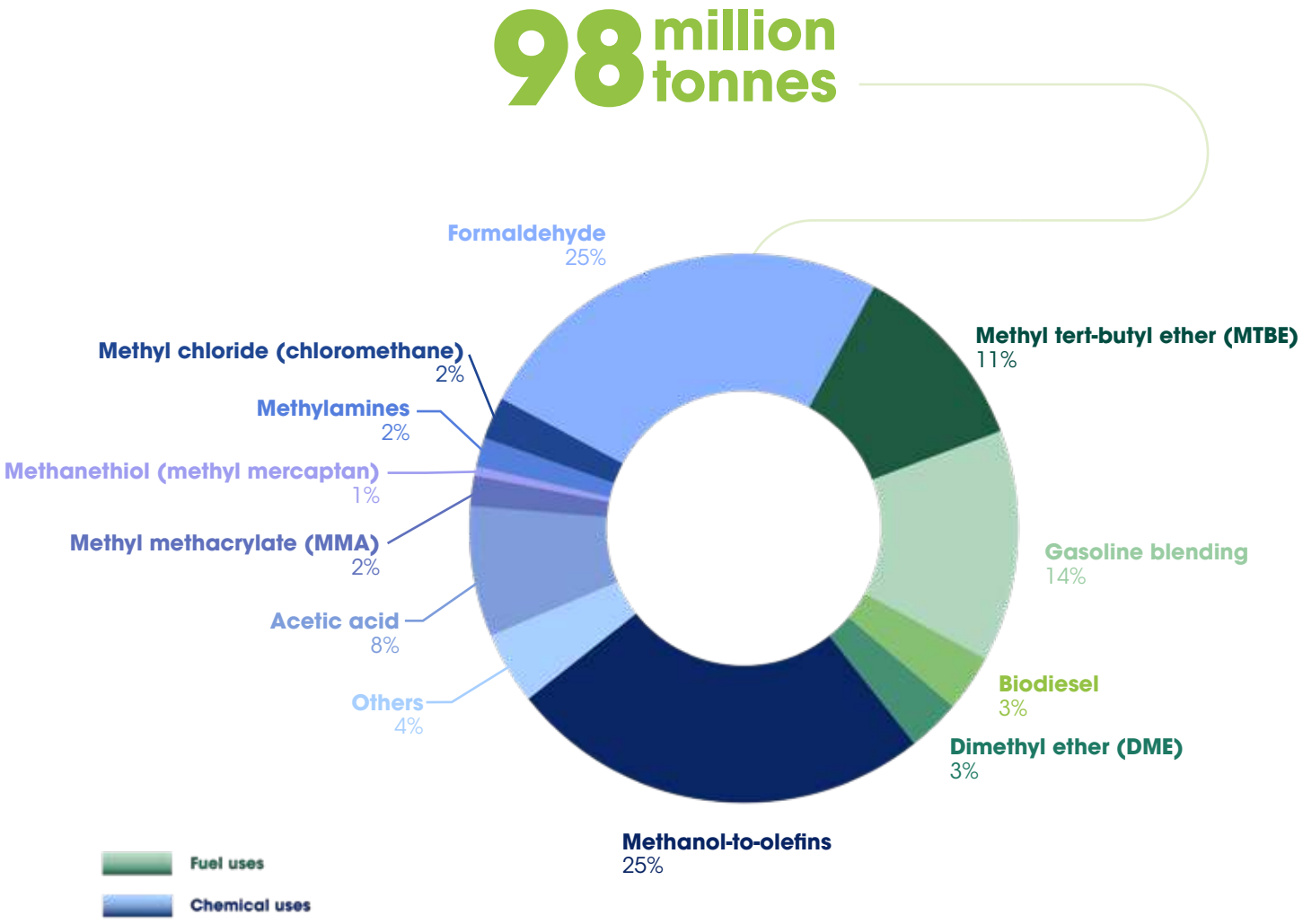
from renewable sources such as biomass combustion, distilleries and biogas. CO_2 capture from these sources needs to be expanded. The production of e-methanol from renewable CO_2 sources, especially the least expensive but most limited ones, might also be in competition with other carbon capture, use and storage applications. Ultimately, the capture of CO_2 from air (DAC) offers the largest potential, but its costs need to decrease substantially.

The combination of bio- and e-methanol production in a single facility could be very beneficial. In such a hybrid plant, the excess CO_2 generated in the production of bio-methanol can serve as the CO_2 source for the production of e-methanol with green hydrogen.

Outlook for renewable methanol.

With current global demand for methanol at close to 100 Mt per year and growing, there is a large potential market for renewable methanol. Methanol, whether from fossil fuels or renewable sources, has the same chemical structure: CH_3OH. As such, renewable methanol could directly replace fossil methanol in any of its current uses, e.g. as a feedstock for the production of various chemicals, materials, plastics and products, and as a fuel for transport, shipping, cooking, heating and electricity production. The current expansion of fossil methanol as a fuel in some applications could also ease the gradual transition to renewable methanol as the distribution and transport infrastructure would remain the same.

Figure 5. Global methanol demand in 2019



Source: *Based on data from MMSA (2020)*

In addition to existing methanol use, renewable green methanol could also replace most petroleum-based hydrocarbons and petrochemicals, either directly or through methanol derivatives, for a potential market requiring billions of tonnes of methanol per year. Production of plastics and aromatics (BTX) from renewable methanol could, for example, be greatly expanded. This would facilitate the transition to a sustainable circular green economy where renewable methanol is uniquely positioned as a future-proof chemical feedstock and fuel.

While the expansion of renewable methanol is currently held back by its higher production cost when compared to natural gas- and coal-based methanol, renewable methanol is one of the easiest-to-implement sustainable alternatives available, especially in the chemical and transport sectors.

Table 1 summarises the benefits and challenges of scaled-up renewable methanol use. A more detailed discussion of the pros and cons of methanol can be found in Annex 1.

Table 1. Pros and cons of methanol and renewable methanol

Pros	Cons
+ Can be produced on an industrial scale from various carbon-containing feedstocks. Natural gas and coal today; biomass, solid waste and CO_2 + H_2 tomorrow	× Production of renewable methanol remains more expensive than fossil methanol
+ Already used to produce hundreds of everyday industrial chemicals and consumer products	× Production of renewable methanol needs to be scaled up
+ Methanol is a liquid at atmospheric conditions. This makes it easy to store, transport and distribute by ship, pipeline, truck and rail	× Competition for renewable feedstock (biomass, CO_2, renewable power, green hydrogen) with other renewable alternatives
+ Only relatively inexpensive and minor modification to existing oil infrastructure needed for methanol storage and distribution	× Renewable methanol requires investment support, technology-neutral public policy, and removal of barriers to access affordable renewable electricity, CO_2 and biomass feedstocks
+ Versatile fuel for internal combustion engines, hybrid (fuel/electric) systems and fuel cells, turbine engines, cookstoves, and boilers	× Fuel standards for methanol need to be expanded to allow for wider use in more countries and for more applications
+ Potential liquid hydrogen carrier	× Only about half the volumetric energy density of gasoline and diesel fuel
+ Low pollutant emissions: no soot (PM), no SO_x, low NO_x. Low-carbon and renewable methanol also reduces CO_2 emissions	× Corrosive to some metals and incompatible with some plastics and materials
+ No inherent technical challenges in scaling up the production of methanol to meet the needs of the transport or chemical industry sectors	× Highly flammable and can lead to explosion if handled improperly, like gasoline, ethanol or hydrogen
+ Methanol is readily biodegradable	× Toxic; can be lethal if ingested

Action areas to foster renewable methanol production

As with any other alternative to fossil fuels, for renewable methanol to take off in the chemical sector and as a renewable fuel, demand and supply have to be stimulated by suitable policies, regulations and mandates. These could include, among others, renewable fuel standards, incentives, carbon taxes, cap-and-trade schemes, long-term guaranteed price floors, contracts for difference (CfD), lower taxes on renewable fuels and feedstocks/products, information campaigns and eco-labelling. Life-cycle analyses (LCAs) and other benchmarks will be needed to weigh up the benefits of each process, material and fuel.

In the transition to fully renewable methanol production, the co-production of green and conventional products with proportionate credit should also be allowed. These include, for example, LCM technologies where green hydrogen and CO_2 are added to the process of methanol production from natural gas.

This would allow for a gradual greening of the methanol produced while keeping costs low. Once the technologies (e.g. electrolyser, CO_2 capture) are scaled up and the cost of renewable power low enough, the share of green methanol, and credits, could increase.

Box 1. How to facilitate the transition to renewable methanol:
Recommendations for industry and governments

1 **Ensure systemic investment throughout the value chain, including technology development, infrastructure and deployment.** Methanol can be utilised in existing internal combustion engines as well as in more advanced powertrains and chemical production processes. Conventional grey and blue methanol can be used today, with greater substitution of green methanol over time. Economies of scale and improved technologies for renewable methanol production will lead to competitive pricing for multiple sectors, and must be supported by targeted investment support in the form of direct subsidies and loan guarantees for production CAPEX (electrolysers, CO_2 capture, and synthesis equipment). Industry and government also need to partner on major cost-lowering and risk-mitigation pilot projects and fuel infrastructure deployment.

2 **Create a level playing field through public policy to facilitate sector-coupling.** Drive investment in renewable electricity from the power sector and biomass utilisation from the agriculture/forestry sector that can be scaled up to reduce the OPEX production costs of renewable methanol. Investment will also be needed in renewable/captured CO_2 through BECCS or DAC. The methanol produced can be used in the transport and industrial sectors. Each sector may find a different pathway to carbon neutrality, and public policy should encourage synergies by sector-coupling.

3 **Support market forces in the chemical sector, focusing on carbon intensity in consumer products.** Renewable methanol can be an essential building block for hundreds of products that touch our daily lives, contributing to a circular economy, benefiting from carbon footprinting and premium pricing mechanisms.

4 **Acknowledge how renewable methanol can contribute to carbon neutrality in "green deals", COVID-19 economic recovery packages and hydrogen strategies.** The criteria used to define support strategies for carbon neutrality must follow inclusive frameworks that include low-carbon liquid fuels and chemical feedstock such as renewable methanol.

5 **Translate the political will for carbon reduction into regulatory measures and support to facilitate long-term growth.** Regulatory measures for fuel standards/quotas should account for the carbon intensity of the targeted market, facilitating pricing incentives to provide stability for sustained growth and investment.

6 **Encourage international co-operation on trade strategies to create jobs and foster competitive new industries for e-methanol in both producing and consuming regions.** As an e-fuel and e-chemical, e-methanol can be produced in regions with ample resources of renewable electricity, using carbon as a carrier in the form of an easily transportable liquid molecule. Investing in e-methanol production capacity in different countries around the world will diversify energy and feedstock supply and reduce political risks.

7 **Institute policy instruments to ensure equitable tax treatment and a long-term guaranteed price floor for renewable methanol and other promising fuels.** Fuel excise and other taxes should be based on energy content and not volume (e.g. USD per kWh, not USD per litre). Energy tax reductions can be provided for renewable fuels, including renewable methanol – both bio-methanol and e-methanol. Taxation policy can "make or break" alternative fuels. A meaningful production support system that could motivate investment is a contract for difference (CfD) scheme, in which advanced renewable fuel production projects bid for, and the winners are awarded, CfDs in so-called reverse auctions (lowest bid wins).

1. CURRENT PRODUCTION AND APPLICATIONS OF METHANOL

Methanol (CH_3OH) is a colourless water-soluble liquid with a mild alcoholic odour. It freezes at -97.6°C, boils at 64.6°C and has a density of 0.791 kilograms (kg) per cubic metre at 20°C. Methanol is an important organic feedstock in the chemical industry, with worldwide annual demand nearly doubling over the past decade to reach about 98 million tonnes (Mt) in 2019 (Figure 6 and Figure 7), while global production capacity has reached about 150 Mt (MI, 2020a; MMSA, 2020).

Since 1995, the average contract price for methanol in Europe has been fluctuating roughly between USD 200 and USD 400 per tonne (t) when adjusted for inflation (see Figure 8). Production costs are about USD 100 to USD 250/t depending on the feedstock (natural gas or coal) and the price of that feedstock.

1.1. Methanol as a raw material

Methanol occurs naturally in fruits, vegetables, fermented food and beverages, the atmosphere and even in space. Historically methanol was commonly referred to as wood alcohol because it was first produced as a minor by-product of charcoal manufacturing, by destructive distillation of wood. In this process, one tonne of wood generated only about 10–20 litres (L) of methanol (along with other products).

At the beginning of the 1830s, methanol produced in this way was used for lighting, cooking and heating purposes, but was later replaced in these applications by cheaper fuels, especially kerosene. Interestingly, up until the 1920s wood was the only source for methanol. From that point on, industrial production of methanol from coal was introduced followed by production from natural gas starting in the 1940s. This shift to fossil resources allowed for a dramatic increase in methanol production capacity.

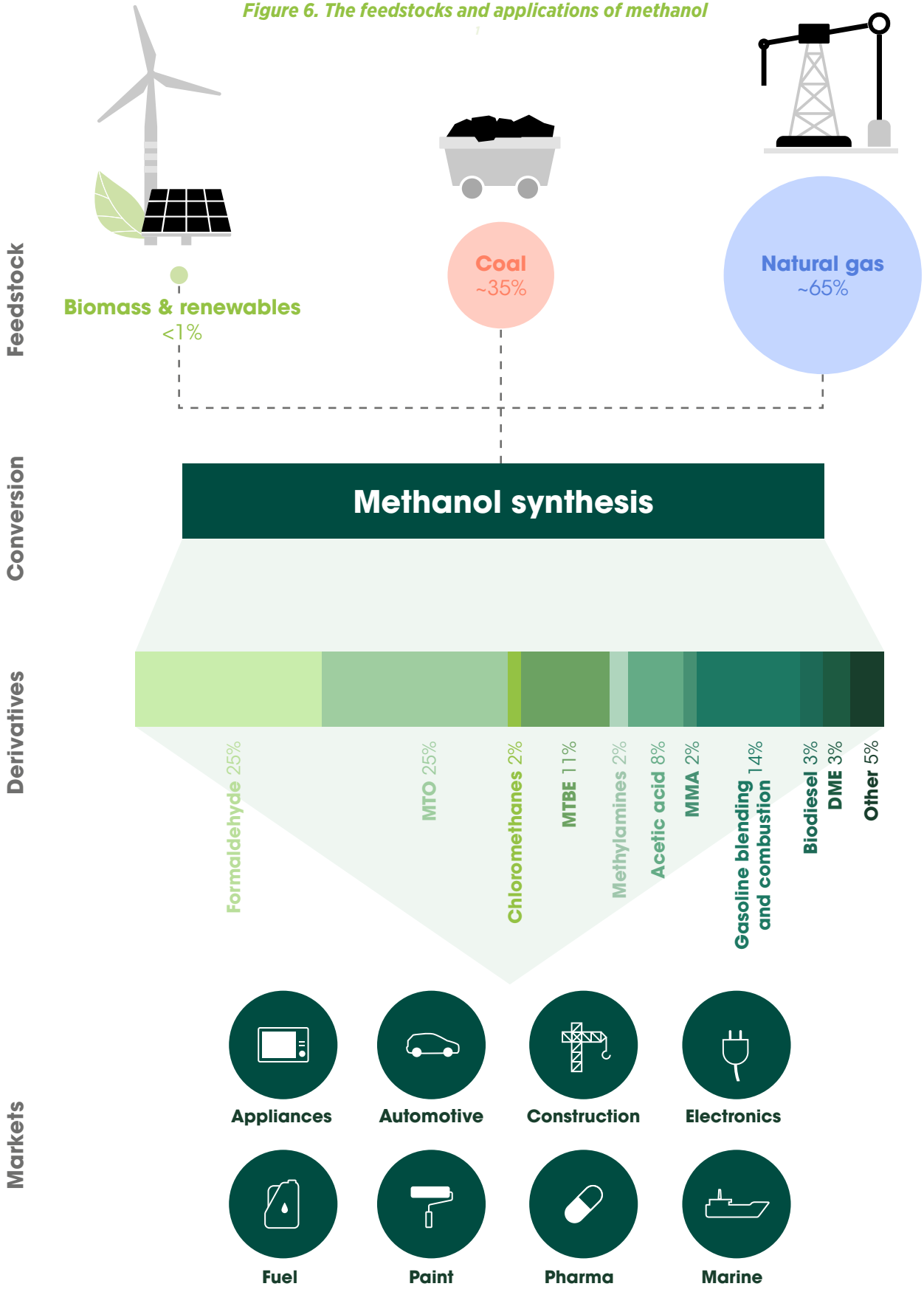
Fast-forward to 2019, of the almost 100 Mt of methanol produced per year (125 billion L), more than 60% was used to synthesise chemicals such as formaldehyde, acetic acid, methyl methacrylate, and ethylene and propylene through the methanol-to-olefin (MTO) route. These base chemicals are then further processed to manufacture hundreds of products that touch our daily lives, from paints and plastics, to building materials and car parts.

Formaldehyde remains the largest-volume chemical product derived from methanol and is mainly used to prepare phenol-, urea- and melamine-formaldehyde and polyacetal resins, as well as butanediol and methylenebis(4-phenyl isocyanate) (MDI). MDI foam is, for example, used as insulation in refrigerators, in doors, and in motor car dashboards and fenders. The formaldehyde resins are then predominantly employed as adhesives in the wood industry in a wide variety of applications, including the manufacture of particle boards, plywood and other wood panels.

Among new uses of methanol, the MTO process, as an alternative to the more traditional production of ethylene and propylene through petrochemical routes, has seen tremendous growth in the past 10 years in China for the production of polyethylene and polypropylene. From essentially no production through this route in 2010, MTO now accounts for about 25% of global methanol consumption (MMSA, 2020).

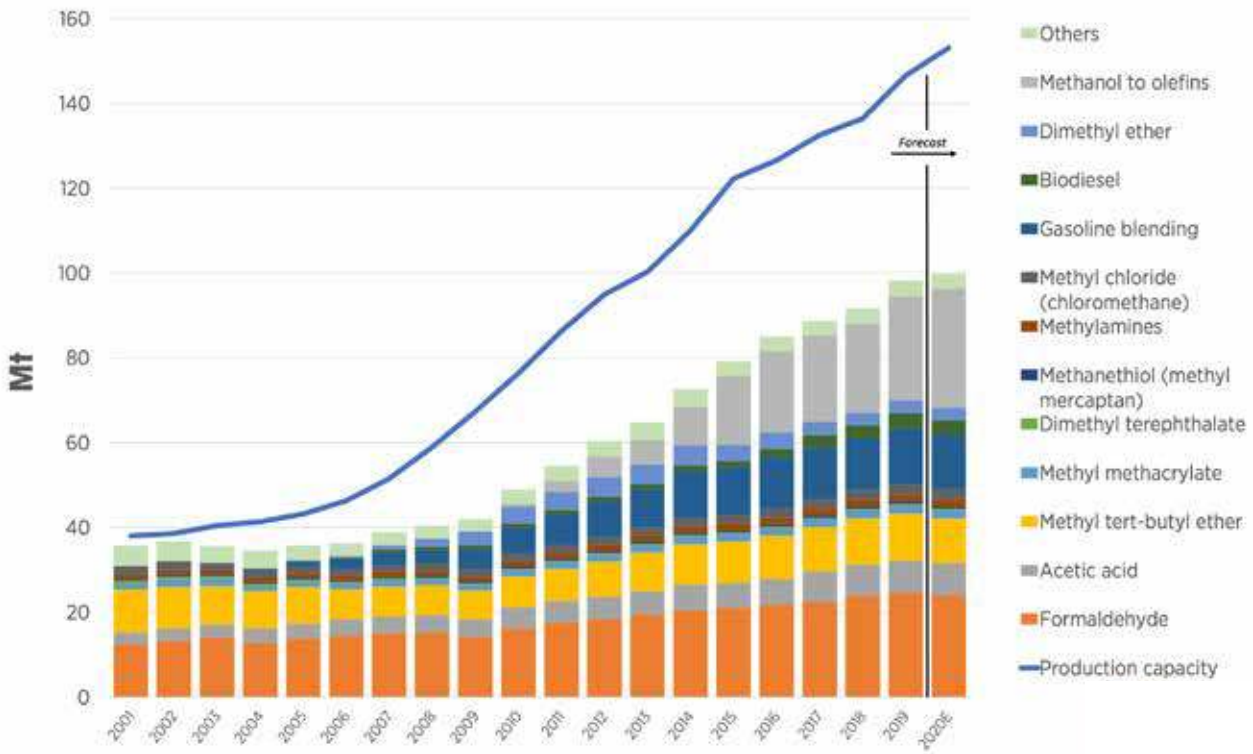
Methanol has many other uses, including as a solvent, antifreeze, windscreen washer fluid and for denitrification at wastewater treatment plants (Olah, 2018).

Figure 6. The feedstocks and applications of methanol



Sources: *Chatterton (2019); Dolan (2020); MMSA (2020).*

Figure 7. Global methanol demand and production capacity (2001-2019)



Source: *Based on data from MMSA (2020).*

Figure 8. Historical methanol sale price (1995-2020)

Note: *Western Europe contract average realised price, FOB Rotterdam.*

Source: *Based on data from MMSA (2020).*

1.2. Methanol as a fuel

The use of methanol as a fuel, either by itself, in a blend with gasoline, for the production of biodiesel, or in the form of methyl *tert*-butyl ether (MTBE) and dimethyl ether (DME), has also grown rapidly since the mid-2000s. Together these fuel uses now represent about 31% of methanol consumption. MTBE has been used as an oxygenated anti-knock fuel additive in gasoline since the 1980s. While MTBE has been banned in some countries such as the United States because of groundwater contamination issues, its use has been increasing in other regions including Asia and Mexico. Biodiesel can be obtained by reacting methanol with fats and oils. However, direct use of methanol as a fuel has seen the largest growth; from less than 1% in 2000, the share of methanol consumption for that purpose has now increased to more than 14%. Due to its high octane rating, methanol can be used as an additive or substitute for gasoline in internal combustion engines (ICEs). Methanol can also be used in modified diesel engines (Bromberg and Cohn, 2009; Bromberg and Cohn, 2010), and advanced hybrid and fuel cell vehicles.

Notably, methanol has only about half the volumetric energy density of gasoline and diesel. If pure methanol is used as a fuel, adjustments to the tank size have to be made if a similar range is to be achieved. Direct methanol fuel cells (DMFCs) can also convert the chemical energy in methanol directly into electrical power at ambient temperature (McGrath et al., 2004).

Because methanol does not produce soot, fumes or odour, it is also widely used in cook stoves (over 5 Mt in 2018 in China alone) (Dolan, 2020). DME, produced from methanol by simple dehydration, is a gas that can be liquefied at moderate pressure, much like liquefied petroleum gas (LPG). DME as a diesel fuel substitute with a high cetane rating and producing no soot emissions (particulate matter [PM]) has also attracted much interest (Semelsberger et al., 2006; Arcoumanis et al., 2008).

DME can also replace LPG in applications such as heating and cooking. Up to 20% DME can be blended with LPG with no or very limited modifications to existing equipment. Methanol can also be used as a fuel to produce heat and steam in industrial boilers, and for electric power generation in gas turbines (Temchin, 2003; Basu and Wainwright, 2001). More than 1 000 boiler units in China consumed 2 Mt of methanol in 2018 (Dolan, 2020).

Methanol has historically been a candidate as an alternative to conventional crude oil-based fuels. This was initially the case at the time of crude oil supply constraints in the 1970s and 1980s. Methanol (fossil) has a high octane rating, and during the 1980s and 1990s was widely tested both as a low blend component and as a pure fuel in large test fleets in many countries, mainly with the goal of reducing air pollution. This interest was driven by the knowledge that methanol is relatively cheap to produce from coal and natural gas, and that it can be used with only minor modification to the existing vehicle fleets and distribution infrastructure.

By the late 1990s, various technological advances were achieving wide acceptance in the automobile industry: direct fuel injection, three-way catalytic converters, reformulated gasoline, etc. These reduced dramatically the emission problems associated with gasoline-powered vehicles, but decreased at the same time the benefits of methanol-based fuels. Simultaneously oil prices remained low meaning that despite being a technical success, methanol was not a commercial success (Olah et al., 2018).

While the interest in methanol-powered vehicles diminished in developed countries, China has recently been active in promoting methanol as a transport fuel, largely to decrease its dependence on imported fuel. Numerous Chinese automotive manufacturers are offering methanol-powered vehicles, including cars, vans, trucks and buses able to run on M85 (85% methanol, 15% gasoline) and M100 (pure methanol), as well as methanol/gasoline blends with lower methanol content (SGS, 2020). Flexible-fuel vehicles able to run on various mixtures of methanol and gasoline, or so called GEM fuels (gasoline/ethanol/methanol), are also available (IRENA, 2019a; Olah et al., 2018; Schröder et al., 2020). These vehicles cost a similar amount to regular cars.

Methanol can also be used in diesel engines, either by co-feeding with a small amount of diesel pilot fuel, the addition of ignition improver (MD95), or the installation of glow plugs. Use of engines specifically optimised for methanol that allow for higher compression ratios are also possible (Schröder et al., 2020). Examples of a fleet of methanol-fuelled taxis and heavy-duty trucks can be seen in Figure 9 and Figure 10. China currently consumes 4.8 Mt of methanol per year for road transport (Dolan, 2020). Methanol as a road fuel is also attracting growing interest in other parts of the world, including Israel, India and Europe, as well as for other applications such as trains and heavy machinery (Landälv, 2017).

Figure 9. Fleet of M100 fuelled taxis in Guiyang City, Guizhou province, China

Source: *Geely (2020).*

Figure 10. Geely M100 truck (2019) in China and M100 truck in Israel (2020).

Source: *Geely (2020); DOR Group (2020).*

While methanol can be used in conventional ICE vehicles, it can also be a fuel for advanced hybrid and fuel cell vehicles. In that case methanol is reformed on board a vehicle to hydrogen, which is fed to a fuel cell to charge batteries in an electric vehicle (EV) or provide direct propulsion in a fuel cell vehicle (FCV).

The use of liquid methanol avoids the need for costly on-board systems able to store and transfer hydrogen gas safely under extreme pressure (350-700 bar) in FCVs. To date, methanol is the only liquid fuel that has been demonstrated on a practical scale in fuel cell-based transport applications.

The potential for on-board methanol reformers to power FCVs has been demonstrated in numerous prototypes constructed and tested by various car companies in the 1990s and 2000s, including Ford, General Motors, Honda, Mazda, Mitsubishi, Nissan and Toyota (Olah et al., 2018).

In the early 2000s, Daimler introduced the NECAR 5 methanol-powered FCV, which in 2002 was the first FCV to drive 5 000 kilometres (km) across the United States from coast to coast (Daimler, 2020). Newer models of car developed by Gumpert Aiways and Palcan Energy are shown in Figure 11 and Figure 12 (Gumpert Aiways, 2020; Palcan Energy Corp., 2020), expanding the range of EVs or FCVs from 300 km to over 1 000 km on a 3-minute fill-up of methanol fuel.

Figure 11. Gumpert Nathalie, methanol-fuelled hybrid fuel cell supercar

Source: *Gumpert Aiways (2020).*

Figure 12. Palcan hybrid methanol reformer/proton-exchange membrane fuel cell passenger bus in China

Source: *Palcan Energy Corp. (2020).*

Maritime transport is another sector that has shown a growing interest in methanol. Currently more than 20 large ships in operation or on order are powered by methanol (DNV GL, 2020). The shipping sector is currently responsible for about 3% of all GHG emissions and 9% of the GHG emissions associated with the transport sector (IRENA, 2019b). Maritime shipping represents 80-90% of international trade. The traditional marine fuel used in ships is diesel bunker fuel, which is relatively high in sulphur.

Even with new regulations set by the International Maritime Organization to reduce the sulphur limit in marine fuels from 3.5% to 0.5%, ships will still emit large amounts of sulphur oxides (SO_x), nitrogen oxides (NO_x) and PM into the atmosphere. In addition, the proliferation of emission control areas (ECAs) around the world, where emission limits are even more stringent, requires the use of very low sulphur fuel oil or marine gasoil, which are much more costly than traditional heavy fuel oil. Because these are far costlier to produce, the shipping industry has been looking for alternatives, among which methanol is a prime candidate.

Methanol, due to its production process, is sulphur-free and when burned produces almost no PM (due to the absence of carbon-carbon bonds) and low amounts of NOx. A number of demonstration projects have been looking into methanol for marine use (SGS, 2020). Conversion of existing large and small ships to methanol can be achieved easily at a moderate cost (Haraldson, 2015). For new builds, the investment cost is similar to traditional ships.

Operating on methanol is already economical, especially in ECAs. Examples of ships running on methanol are shown in Figure 13 and Figure 14 (MI, 2020b). One example is the Stena Germanica, a 50 000 t, 32 000 horsepower ferry operating between Germany and Sweden that was retrofitted in less than three months to run on methanol. The world's largest methanol producer and distributor, Methanex, also operates part of its fleet of 50 000 deadweight tonnage (DWT) chemical tankers on dual-fuel MAN engines that can operate on diesel fuel or methanol. Projects to introduce methanol-powered fuel cell systems for ship propulsion are also under way to improve efficiency and emissions compared to ICEs (Chatterton, 2019; Fastwater, 2020).

Figure 13. Methanol-powered Stena Germanica 50 000 DWT ferry operating between Gothenburg and Kiel

Source: *Stena Line (2020).*

Figure 14. Ocean-going vessel powered by methanol

Source: *Waterfront Shipping/MOL (2020).*

For aviation purposes methanol could be converted to kerosene-type aviation fuels using a process similar to the methanol-to-gasoline (MTG) process (Wang et al., 2016; Wormslev and Broberg, 2020). Methanol itself is not usually considered the most suitable fuel due to its lower volumetric energy density compared to kerosene. However, methanol could possibly be a candidate for more advanced hybrid planes using a combination of fuel cell and battery to run electric turbofans or turboprops (Soloveichik, 2018). This type of hybrid electric aircraft would have a number of advantages, including less pollution, noise and emissions, with energy usage reduction in the range of 40-60%. This would somewhat counterbalance the lower energy density of methanol. This type of hybrid aircraft would be especially suited to regional flights. Methanol has already been introduced in drone-type devices to considerably increase their range and flight time. A tiny methanol combustion motor charges the battery during flight, allowing for longer flight times and instant refuelling. DMFCs have also been successfully tested in unmanned aerial vehicles.

1.3. Storage, transport and distribution of methanol

In most applications, a liquid energy storage medium such as methanol would be preferable to a gaseous one. In the transport sector in particular, a transition from liquid fossil fuel-derived products (gasoline, diesel fuel, kerosene etc.) to a renewable and sustainable liquid fuel would be highly desirable. This would enable the use of the existing infrastructure with only minor modifications and at a low cost.

Methanol is already a globally available commodity with extensive distribution and storage capacity in place. Millions of tonnes of methanol are transported each month

to diverse and scattered users, by ship, barge, rail and truck. Methanol can also be transported through pipelines, much like oil and its products. Refuelling stations dispensing methanol for cars, buses and trucks are essentially identical to current filling stations, requiring very little change in consumer habits (Figure 15 and Figure 16). In most cases the same tanks can be used. Minor changes to the refuelling lines, gaskets, etc. might be needed to accommodate methanol. Rather than gasoline or diesel fuel, the consumer simply fills their tank at the local service station with a different liquid fuel. Methanol pumps can be placed alongside existing gasoline or diesel dispensing pumps. According to a study in the United States (Chatterton, 2019), the cost of a methanol filling station is also the same as a gasoline/diesel one, and much cheaper than hydrogen refuelling stations that each cost in excess of USD 2 million for only a small fraction of the capacity of a methanol station. Methanol refuelling infrastructure is also much cheaper than liquefied natural gas (LNG) stations, which are currently receiving special attention in Europe as a result of the so-called Alternative Fuel Infrastructure Directive 2014/94/EU from 2014 (EU, 2014).

Figure 15. Methanol stations in China

Source: *Methanol Institute.*

Source: *Palcan Energy Corp (2020).*

Figure 16. M15 dispensing pump alongside gasoline and diesel fuel dispensers at a filling station, and M100 dispensing pump in Israel

Source: *Dor Group (2020).*

Methanol bunkering for ships is both easy and clean. Because methanol is a liquid at atmospheric pressure, it can be stored much like bunker fuel. The infrastructure cost to store methanol is therefore low, especially compared to LNG or hydrogen alternatives (MI, 2020c). Methanol is already available in over 100 major ports today. It is also readily biodegradable (MI, 2020c; Clary, 2013).

Methanol derivative DME has physical properties similar to LPG fuels and can use existing land-based LPG infrastructure. Since there are numerous LPG filling stations, a transition to DME using the same technologies could be less costly than building completely new infrastructure (Figure 17 and Figure 18).

Figure 17. DME filling station and pump in Shanghai, China in 2008

Source: *IDA (2020).*

Figure 18. Bio-DME filling station in Sweden in 2011

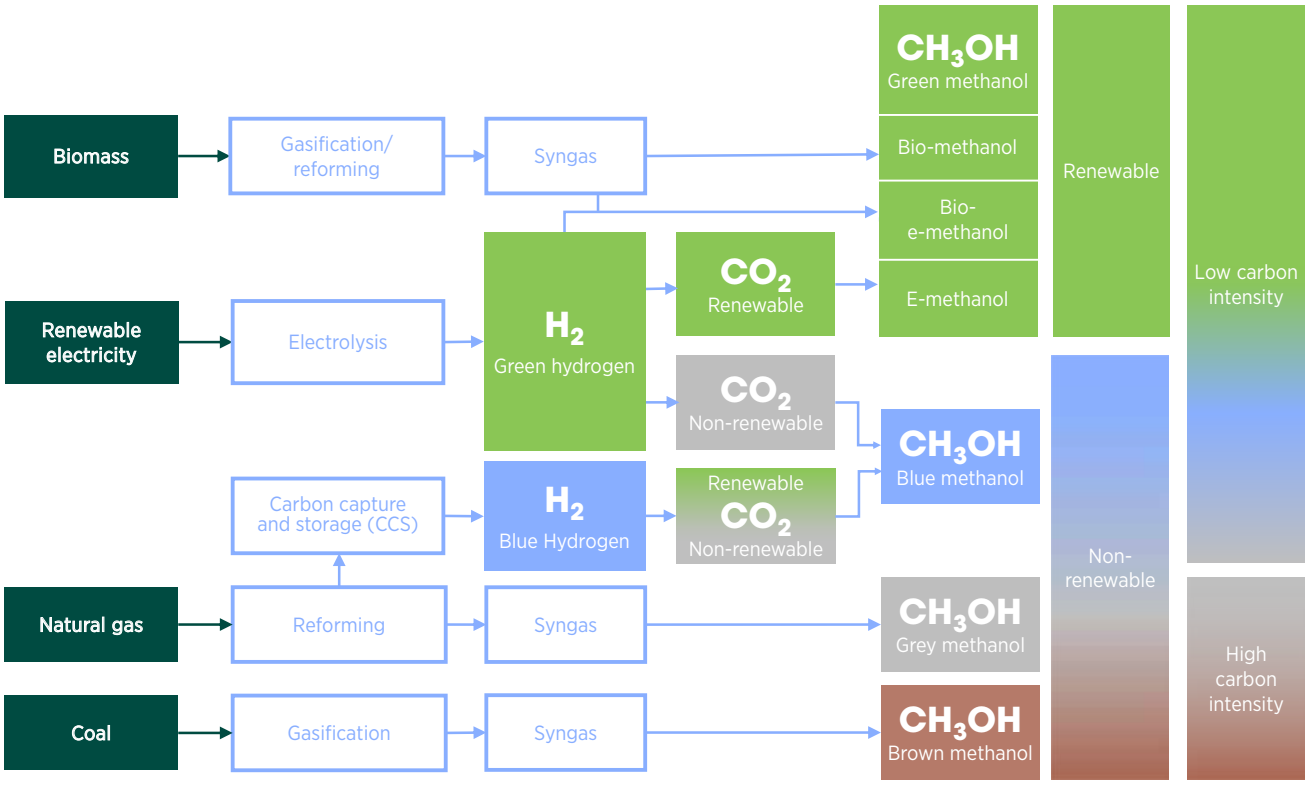
Source: *Chemrec (2020).*

2. PRODUCTION PROCESS AND TECHNOLOGY STATUS

Global methanol consumption reached 98.3 Mt in 2019, and is expected to reach more than 120 Mt by 2025 (MMSA, 2020; Berggren, 2019) and 500 Mt by 2050 (Saygin and Gielen, forthcoming). As the world's largest methanol producer and consumer, China accounted for more than half of total global demand, consuming around 55 Mt of methanol in 2018, a quarter of which was utilised in fuel applications. This was followed by the rest of Asia (excluding China), Europe, North America and South America. In the next ten years, most future growth in demand is expected to arise in China, with the expansion of applications such as transport and heating fuels, and MTO plants (Berggren, 2019).

Methanol can be produced from concentrated carbon sources, such as natural gas, coal, biomass, by-product streams, or even carbon dioxide (CO_2) from various sources including industrial flue gases or direct air capture (DAC) (Olah et al., 2018; Bertau et al., 2014). A simplified overview of the steps involved in methanol production is given in Annex 2. However, for mostly economic reasons methanol is still almost exclusively produced from fossil fuels. About 65% of methanol production is based on natural gas reformation (grey methanol), while the rest (35%) is largely based on coal gasification (brown methanol) (Dolan, 2020). Currently, only about 0.2% comes from renewable sources (green methanol).

Figure 19. Proposed classification of methanol from various feedstocks



Most methanol production capacity using coal is located in China, where vast coal reserves are available. Production from natural gas is the norm in the rest of the world.

Depending on the feedstock and associated carbon emissions, methanol can be categorised as high or low carbon intensity (Figure 19). Methanol produced from coal and natural gas without carbon capture or renewable power input is generally considered high carbon intensity (brown and grey methanol). Methanol production based on the use of renewable energy in various forms, fossil fuel with carbon capture, or a combination thereof are considered to have lower carbon intensity (low-carbon methanol, blue and green methanol; see Figure 19). Methanol can also be classified as renewable and non-renewable. To qualify as renewable, all feedstocks used to produce the methanol need to be of renewable origin (biomass, solar, wind, hydro, geothermal, etc.).

To produce methanol, natural gas and coal first have to be converted to synthesis gas (syngas), a mixture of carbon monoxide (CO), hydrogen (H_2) and carbon dioxide (CO_2). In the case of coal, syngas is obtained by gasification that combines partial oxidation and steam treatment at high temperature (800-1 800°C depending on the process and feedstock) (Bell et al., 2010). To produce syngas from natural gas a number of processes are available including steam reforming, partial oxidation dry reforming, autothermal reforming or a combination thereof. These are high-temperature processes (> 800°C). The syngas obtained by coal gasification requires much more pretreatment, conditioning and adjustment to remove impurities and contaminants (tars, dust, inorganic substances) to optimise its composition for methanol synthesis.

Ideally, the syngas after conditioning should have a H_2 to CO ratio of at least two to one for optimal synthesis of methanol. Due to the low hydrogen/carbon (H/C) ratio of coal, the obtained syngas is rich in carbon oxides (CO and CO_2) and deficient in hydrogen. Before being sent to the methanol unit, the syngas must thus be subject to a water-gas shift (WGS) reaction to enhance the amount of hydrogen formed. Some of the CO_2 produced in the process must also be separated, and is generally simply vented to the atmosphere. Natural gas has fewer impurities, which are easier to separate, and a much higher H/C ratio, meaning that much less syngas conditioning is needed. Due to its higher H/C ratio, the CO_2 emissions associated with the production of methanol from natural gas are also substantially lower than from coal (about 0.5 kg of carbon dioxide equivalent [CO_2-eq] per kg methanol for natural gas compared to 2.6-3.8 kg CO_2-eq/kg methanol for coal [Kajaste et al., 2018; MI, 2020c]).

After conditioning, the syngas is converted into methanol by a catalytic process generally based on copper, zinc oxide and aluminium oxide catalysts (Bertau et al., 2014; Olah et al., 2018). Distillation of crude methanol follows to remove the water generated during methanol synthesis and any by-products.

A typical world-scale methanol plant using natural gas as the feedstock has a production capacity of about 3 000-5 000 t per day or 1-1.7 Mt per year (Sheldon, 2017).

2.1. Low-carbon methanol

To reduce the carbon intensity of methanol production from natural gas, a number of companies have developed low-carbon methanol (LCM) processes. There are several ways to reduce CO_2 emissions while using natural gas. One option is to inject CO_2 from some other process into the methanol synthesis loop. Another is to decarbonise the first step in methanol production from natural gas, which is the reforming step to syngas. This step is very energy-intensive, requiring part of the natural gas feedstock to be burned to generate the heat for the reforming of the natural gas at a temperature > 800°C, generating at the same time CO_2. By reforming natural gas via electrical heating with renewable power, these CO_2 emissions can be eliminated. Combining these CO_2 emissions with hydrogen produced by electrolysis of water with renewable energy in the methanol synthesis loop is yet another way to lower the carbon intensity of methanol production from natural gas. These and various other combinations of grey/blue and green methanol production constitute hybrid solutions that could facilitate the progressive introduction of green methanol and allow methanol production facilities to reduce their carbon emissions.

Methanex Corporation produces LCM at its Medicine Hat (Canada) plant by injecting CO_2 captured from a neighbouring industrial facility into the methanol synthesis loop. This process significantly reduces GHG emissions when the LCM is utilised as a fuel.

According to Methanex, a car that relies entirely on LCM would emit 30% less CO_2 per kilometre, from well-to-wheel, compared to a gasoline-powered car (Hobson and Márquez, 2018; Methanex, 2018).

Other methanol producers, including Qatar Fuel Additives Company Limited, have implemented CO_2 recovery plants to extract the CO_2 from their flue gas and re-inject it into the methanol synthesis loop, reducing both GHG emissions and water consumption (QAFAC, 2020; Hobson and Márquez, 2018).

In China, Baofeng Energy has started the construction of a green hydrogen generation plant that will be powered by a 200 megawatt (MW) photovoltaic (PV) power plant and produce about 13 000 t of H_2 per year (160 million cubic metres [m^3]) (Hill, 2020). The green hydrogen obtained will be fed into a coal-based methanol plant to increase capacity and reduce carbon emissions. The oxygen co-produced in the electrolysis step will replace part of the air-separated oxygen used for coal gasification, reducing the cost of hydrogen production. This plant is expected to start producing green hydrogen in 2021.

In Canada, Advanced Chemical Technologies is planning to build a 5 000 tonne per day methanol plant based on natural gas, waste CO_2 from adjacent industries, and H_2 produced by a large 660 MW electrolyser powered by hydroelectricity. Thus, this plant will emit no CO_2 and in addition recycle some CO_2 emitted by industry into e-methanol – methanol produced from renewable electricity (AChT, 2020). The advantage is also that an entire plant dedicated only to renewable methanol is not needed, reducing the cost of the renewable methanol produced.

There are also other large-scale technologies for producing LCM from natural gas that yield similar emission reductions. Among others, Johnson Matthey has developed a process called Leading Concept Methanol that incorporates a gas-heated reformer in combination with an autothermal reformer (GHR+ATR). This produces LCM by utilising renewable electricity for all of the compressor drives, including the air separation unit air compressors. Haldor Topsoe is developing a compact fully electrified methane steam reformer named eSMR (electric steam methane reforming) (Wismann et al., 2019).

2.2. Renewable methanol

Growing concern about global climate change due to anthropogenic GHG emissions has prompted governments, policy makers, industry and scientists to start actively looking for ways to "green" their activities. In this context, renewable methanol produced sustainably can be part of the pathway to eventually achieve the decarbonisation of the chemical and transport sectors. Ultra-low-carbon or net carbon-neutral renewable methanol can be produced from a variety of sources. Renewable methanol produced from biomass such as forestry and agricultural waste and by-products, biogas, sewage, municipal solid waste (MSW) and black liquor from the pulp and paper industry is normally called bio-methanol. By comparison, when obtained from carbon dioxide and green hydrogen produced with renewable electricity, it is generally called "e-methanol".

Bio-methanol and e-methanol from renewable sources and processes are chemically identical to fossil fuel-based methanol, but give rise to significantly lower GHG emissions during the entire life cycle. In addition, the use of renewable methanol can reduce dependency on fossil energy imports and stimulate local economies. A number of companies are already producing bio-methanol and e-methanol across the world. In addition, more companies and institutions have built prototype and demonstration units or have active R&D in that field. A list of existing and planned renewable methanol facilities and demonstrations can be found in this chapter and also in Annex 4.

Bio-methanol from biomass and MSW

The technologies used in the production of methanol from biomass and MSW are relatively well-known since they are similar to or the same as technologies used in the commercial gasification-based industry, where feedstocks are usually coal, heavy residual oil and natural gas. However, the gasification aspect differs in feedstock preparation. Scaling-up from advanced demonstration plants to full-scale application still lies ahead for a majority of technologies, but some large plants are up and running or close to being ready for start-up. The main processes in a conventional methanol plant are: feedstock pretreatment, gasification, WGS, gas cleaning, methanol synthesis and purification.

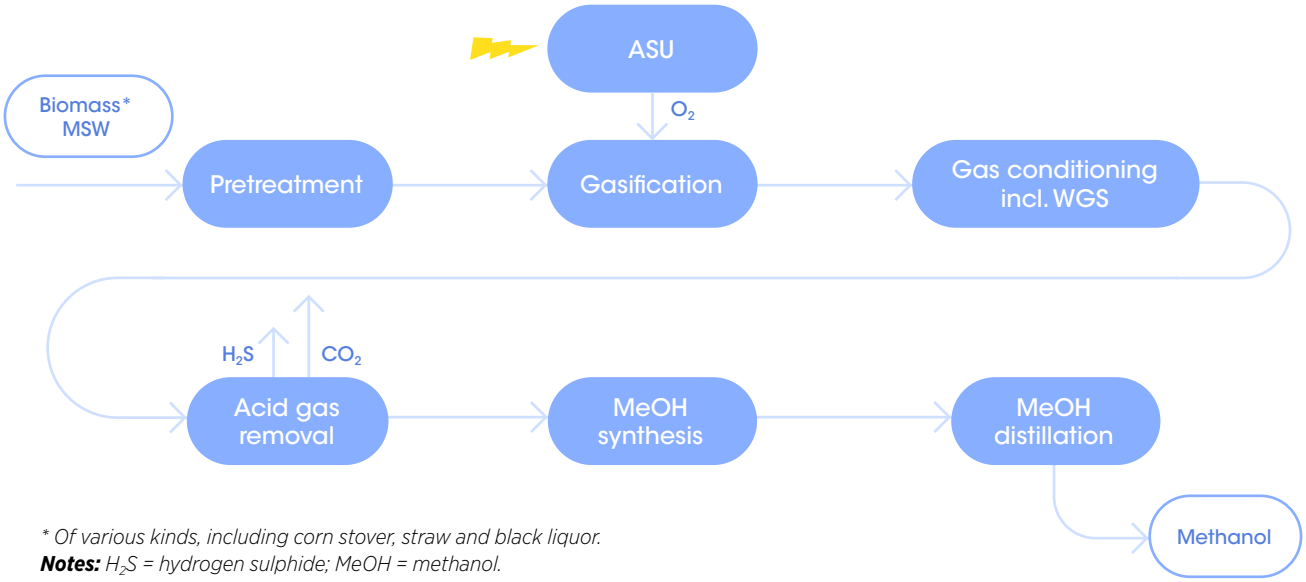
In the gasifier, the feedstock is gasified into synthesis gas (syngas), a mixture of mainly carbon monoxide (CO) and hydrogen (H_2), as well as CO_2 and water (H_2O). Depending on the type of gasifier, the syngas will also contain low levels of hydrocarbons and traces of various components originating from the feedstock or formed during gasification. Gasification can be characterised as a partial (under- stoichiometric) combustion. The oxidising agent is pure oxygen (typically 99-99.5%) in order to avoid a dead load of inert molecules in the produced syngas. The presence of inerts affects the efficiency and yield in the methanol synthesis, and increases the size of the whole syngas handling system, increasing plant costs. The exact ratio between feedstock and oxygen is dependent on several factors where feedstock reactivity, gasifier temperature, feedstock slag behaviour and syngas composition all are important parameters. Using a minimum amount of oxygen is always of interest, because it will reduce the cost of operation and maximise the syngas yield. Theoretically, there is a trade-off between oxygen purity, plant costs, product yield and electricity cost (affects purity of oxygen). Commercial plants are run with high-purity oxygen, which is a clear indicator of where the optimum purity, in most cases, is expected to be found.

The raw untreated syngas leaving the gasification step needs to be cleaned and conditioned to meet the quality level stipulated by the methanol synthesis provider.

These process steps vary considerably depending on feedstock and gasifier technology. Syngas cleaning can include units for the removal of, for example, tars, dust and other trace components, and an acid gas removal unit for CO_2 and sulphur components. Gas conditioning normally includes adjustment of the H_2/CO ratio to around 2 to 1 for optimal methanol synthesis and methane reforming in order to maximise the syngas yield and avoid energy loss in the form of methane leaving the methanol synthesis unit as a purge stream. Methane reforming is not usually needed in current commercial technologies gasifying oil and coal as they have gasification units operating at such a high temperature that methane formation is low – normally under 0.5%. The various process units are described further below.

A general scheme for a gasification-based methanol plant utilising various biomass materials or MSW is shown in Figure 20. When utilising renewable feedstock the first three blocks in the process scheme of Figure 20 are different compared to a plant fed with coal or heavy residual oil. These are (a) the pretreatment of the feedstock, (b) gasification and (c) gas conditioning/cleaning. Typical biomass gasification schemes were described by Hannula and Kurkela (2013) and by GTI (2019). The unit adjusting the H_2 to CO ratio (the WGS) and the acid gas removal (AGR) unit cleaning the syngas of most of its CO_2 and of all its sulphur components are the same as or very similar to commercial technologies used extensively today.

Figure 20. Gasification-based methanol plant – general scheme



** Of various kinds, including corn stover, straw and black liquor.*
Notes: *H_2S = hydrogen sulphide; MeOH = methanol.*

This is even more the case for the methanol synthesis unit, because when the syngas reaches this unit its components are virtually the same regardless of origin.

(A) FEEDSTOCK PRETREATMENT

Most feedstocks for the bio-methanol plant are solid in nature and need to be homogenised in some way before being fed into the gasifier. This is important from both the process control and feeder system design perspectives. The technological challenge of pushing solids at an even flowrate against pressure leads to a gasifier pressure that is kept comparably low, at 5-10 bar. An inert gas may be needed to make the feed system work properly and safely. However, minimising this flow of inert gas is important to minimise the level of investment in the overall syngas system and for plant efficiency. If the feed is in liquid form, as with black liquor from pulp and paper mills, the feeding system is simpler and in line with a heavy residual oil feeding system. These feeding systems can pressurise the gasification unit to high pressure, 30-60 bar.

(B) GASIFICATION

The heart of the gasification unit is the gasifier. This is a high-temperature converter of feedstock into syngas (including various impurities) where the necessary heat for reactions is usually provided by the combustion of a fraction of the feedstock with pure oxygen.

Alternatively, the required heat for gasification can be supplied indirectly through some kind of heat exchange. Both versions are practised for biomass- and MSW-type feedstocks, while commercial processes, with a few exceptions, use partial oxidation with oxygen.

Gasifier technology can be classified into two categories, non-slagging and slagging, where the first is the common variant for renewable feedstocks, while the latter is, with few exceptions, used for gasification of fossil feedstocks. Non-slagging means that inert material present in the feedstock is not allowed to smelt in the gasifier (it would clog the vessel with severe consequences), while slagging gasifiers run above the smelting point of the slag. The gasifier then produces a floating slag. The maximum non-slagging temperature is 800-900°C, while the slagging temperature typically is above 1 000°C. The hot zone in a non-slagging gasifier cannot have hot spots (which would lead to local melting of slag) and there is thus no flame. As a consequence, certain gasification reactions are less complete than reactions occurring in a slagging gasifier where the local temperature in the flame can be very high, towards 2 000°C. The former has a hot bed where most of the reactions take place, while the latter has a very hot flame through which the feedstock needs to pass. As a result of the non-slagging mode, methane and tars form in the gasifier, which need to be handled downstream. The slagging gasifier has very little formation of methane and tars.

Table 2. Examples of syngas conditioning and cleaning processes

Impurities to be removed	Process	More (M) or less (L) common
Particles	Particulate filter	M
Tar and methane	Reform for tar and/or methane decomposition	M
COS	COS hydrolysis converting COS to H_2S	L
Chlorine and fluorine components	HCl and HF removal	L
Sulphur components	AGR process either with CO_2 removal or separately	M
CO_2	AGR process either with H_2S removal or separately	M

Notes: *COS = carbonyl sulphide; HCl = hydrogen chloride; HF = hydrogen fluoride.*

(c) GAS CONDITIONING AND CLEANING

Aftertreatment is different depending on the type of gasifier. Feedstock composition, MSW and different types of biomass material may also affect aftertreatment requirements because certain feedstocks introduce species that are unwanted in downstream processes. These types of processes are mainly required for non-slagging gasifiers. Most common impurities and how to handle them are listed in Table 2. An example on how conditioning and cleaning can be achieved is described in NextChem (2020a).

Gasification-based projects and developments

From a technological viewpoint the key to successful commercialisation is to convert the feedstock to the syngas quality specified by the technology providers of the methanol synthesis unit. Syngas quality requirements are similar regardless of the synthesis technology placed upstream. Therefore, technology capable of generating such high-quality syngas as that used with Fischer-Tropsch technology for the production of various hydrocarbon type fuels (e.g. gasoline, diesel, kerosene) can be utilised in methanol production plants.

Gasifier technologies can be grouped depending on the design principles they utilise. Table 3 classifies each technology with respect to two characteristics. One deals with how the gasifier reactor is heated, and the other describes the gasification principle, in brief.

In Table 4 various gasification technologies are named by the technology owner or by the licensor developing and commercialising the process.

The gasifier unit often consists of two or more parallel trains that are identical in design. There are three reasons for this: (1) the degree of scaling-up from a previous design (maybe a demonstration stage) becomes too great, (2) the plant as a whole has a (part-load) redundancy in case one of the gasifier trains needs to be shut down, and (3) gasification technology is often more maintenance-intensive, making parallel trains preferable. For other units in the total process set-up, single units are common, meaning that economies of scale in the rest of the plant have a positive effect on production costs.

Table 4 provides information on where, when and how the various gasification technologies are currently applied or intended for use. Further information regarding performance is covered in Chapter 3.

Table 3. Gasifier design principles

Heating principle	
DO_2	Directly (D) heated via partial combustion with oxygen (O_2)
IH	Indirectly heated (IH), can be in different ways

Gasifier type	
BB	Bubbling bed (BB) principle
UO_2	Updraft (U), oxygen (O_2) injected together with steam
EF	Entrained flow (EF) (fuel and O_2 injected together in a burner device)
U-IH	Updraft (U), indirectly heated (IH)

Table 4. Gasification technologies and their application

Gasification technology Name/owner	Heating principle	Type	Feedstock	Project, reference	Project phase	Product	Plant capacity (unit varies) kt/year
SES Gasification Technology (U-Gas)	DO_2	BB	Biomass/ MSW	Trans World Energy, Florida (US) (Trans World Energy, 2020)	FEED done, start-up Q2 2023	Methanol	875 kt/y
NextChem Technology	DO_2	UO_2	MSW	ENI Refinery, Livorno, Italian (IT) (NextChem, 2020b)	Basic engineering ready Q3 2020	Methanol	115 kt/y
			MSW/ waste wood	LowLand Methanol (NL) (LowLands Methanol, 2020)	Start-up early 2023	Methanol	120 kt/y
PDQ/ Thyssenkrupp	DO_2	EF	Biomass (torrefied)	BioTfueL Demo Project (FR) (BioTfuel, 2020)	Operational	FT products (slipstream based)	15 MWt of biomass
HTW/ Thyssenkrupp	DO_2	BB	Biomass	Värmlands-metanol (SE) (Värmlandsmetanol, 2017)	Planning	Methanol	100 kt/y
TRI	IH	BB	MSW	Fulcrum (US) (TRI, 2020)	Start-up Q4 2020	FT products	40 000 m^3/y
Bioliq/KIT	DO_2	EF	Pyrolysis oil from straw	Bioliq Demo project (DE) (KIT, 2020)	Operational	Gasoline via DME	5 MW_t of biomass
Chemrec	DO_2	EF	Black liquor	BioDME demo plant (SE) (Chemrec, 2020)	Idling	DME (via methanol)	4 t/d
Enerkem (Enerkem, 2020a)	DO_2	BB	MSW	Edmonton (CA)	Operational	Ethanol (via methanol)	30 kt/y
	DO_2	BB	MSW	Quebec (CA)	Announced construction	Ethanol (via methanol)	35 kt/y
	DO_2	BB	MSW	Rotterdam (NL)	Engineering	Methanol	215 kt/y
	DO_2	BB	MSW	Saragossa (SP)	Engineering	Methanol	215 kt/y
Sungas and GTI (U-Gas)	DO_2	BB	Biomass	GTI demo, Chicago (US) (SunGas Renewables, 2020)	Operational	Syngas	5 MW_t of biomass
TCG Global	IH	U-IH	Biomass	Red Rock Biofuels (Red Rock Biofuels, 2020)	Under Construction Start-up 2021	FT products	58 000 m^3/y

Notes: *FEED = front-end engineering design; FT = Fischer Tropsch; kt/y = thousand tonnes per year; MWt = megawatt thermal; t/d = tonnes per day.*

So far, there is little long-term operational experience of large plants gasifying biomass or MSW and producing syngas for further synthesis into a product. However, there are (not described in this report) plants gasifying MSW or biomass and generating gas for combustion for heat and power. The differences between these two applications are substantial, but are currently being bridged through a number of advanced projects under way.

Enerkem has gasified MSW in its Edmonton, Canada, facility for several years (Figure 21). It has experienced operational issues for a number of reasons, but operations are improving. In 2019, 60 kt of MSW feedstock was gasified compared to a nameplate capacity of 100 kt/y. During 2019, Enerkem had two scheduled down-time periods, which affected the result and explains part of the difference. From start-up in 2015 until the end of 2019, the plant completed more than 10 000 operational hours and produced 4 million L of methanol. A methanol to ethanol conversion unit was installed in 2017 and 2018, and was brought on stream late in 2018. The plant has since produced ethanol.

Four of the projects listed in Table 4 use externally produced H_2 instead of having a WGS unit to adjust the H_2/CO ratio to about 2. They are three Enerkem projects (Quebec, Rotterdam, Saragossa) and the LowLands Methanol project. Specifically, the Enerkem plant in Quebec is planning to incorporate dedicated green hydrogen from an 87 MW electrolyser and expects to increase the total bio-methanol capacity up to 100 kt/y. These projects demonstrate the combined bio-methanol/e-methanol process described below under "Combination of bio- and e-methanol production".

Projects under way as per Table 4 have been ranked as achieving technical readiness level (TRL) 8 or 9, where TRL 8 stands for "First of a kind commercial system" and TRL 9 "Full commercial operation."

Figure 21. Enerkem's MSW to biofuels (methanol and ethanol) plant in Alberta, Canada.

Source: *Enerkem (2020b).*

Bio-methanol from biogas

Biogas production is common in the world. For example, Europe had almost 18 000 production units in operation in 2019 (Wellinger et al., 2019a). Of these units, 540 (3%) were upgrading biogas to biomethane of pipeline quality to be able to inject the gas into the natural gas grid. Europe has approximately 3 570 compressed natural gas (CNG) filling stations (Wellinger et al., 2019b), and 420 of them deliver pure biomethane (not mixed with natural gas). The remaining biogas production plants (97%) use the biogas (with minimum upgrading) for local heat and power generation. In 2019, Europe had 10 500 MW of power capacity installed using biogas as feedstock. In some locations biomethane is used as a co-feed with natural gas in existing methanol production facilities (see Table 5).

Since 2018, the German chemical company BASF has been using biomethane as a co-feed with natural gas in its existing methanol production facility in Ludwigshafen, Germany (BASF, 2018). As a result, GHG emissions are reduced by at least 50% compared with conventionally produced methanol. The renewable part of the product is certified according to the REDcert standard (REDcert, 2020), which is a standard for biofuels recognised by the European Commission under the Renewable Energy Directive (RED).

Since 2009, the Dutch methanol producer OCI/BioMCN has, in a similar way to BASF, produced bio-methanol as part of its methanol production (Compagne, 2017). The bio-methanol has been certified by DEKRA according to International Sustainability and Carbon Certification. Besides exchanging part of their natural gas feedstock with biomethane, they have also used glycerine and renewable CO_2 as renewable feedstocks. BioMCN bio-methanol production capacity is approximately 60 000 tonnes per year (t/y). Another OCI plant can be found in Texas. That plant's overall capacity reached around 1 075 kt/y in 2019 and plans to increase the bio-methanol share of its output (OCI, 2020).

A general scheme for a biogas-based methanol plant is shown in Figure 22. This is a simplification of schemes that can be found in literature, for example by Pedersen and Schultz (2012). Biogas needs to be pretreated to attain the same quality as fossil natural gas before being fed into the methane reformer. CO_2 from such pretreatment may be fed back into the produced syngas depending on the type of methane reformer being used. Alternatively, methane can be reformed together with part of the CO_2. Linde has developed a concept utilising so called "dry reforming" (Linde, 2020), where part of the steam has been replaced with CO_2. In line with this development, Linde has together with BASF presented a new way to produce DME where dry reforming is combined with a novel DME synthesis process (Brudermüller, 2019). The latter new development comprises direct synthesis of DME from syngas.

Table 5. Methanol plants co-fed with a mix of natural gas and biomethane

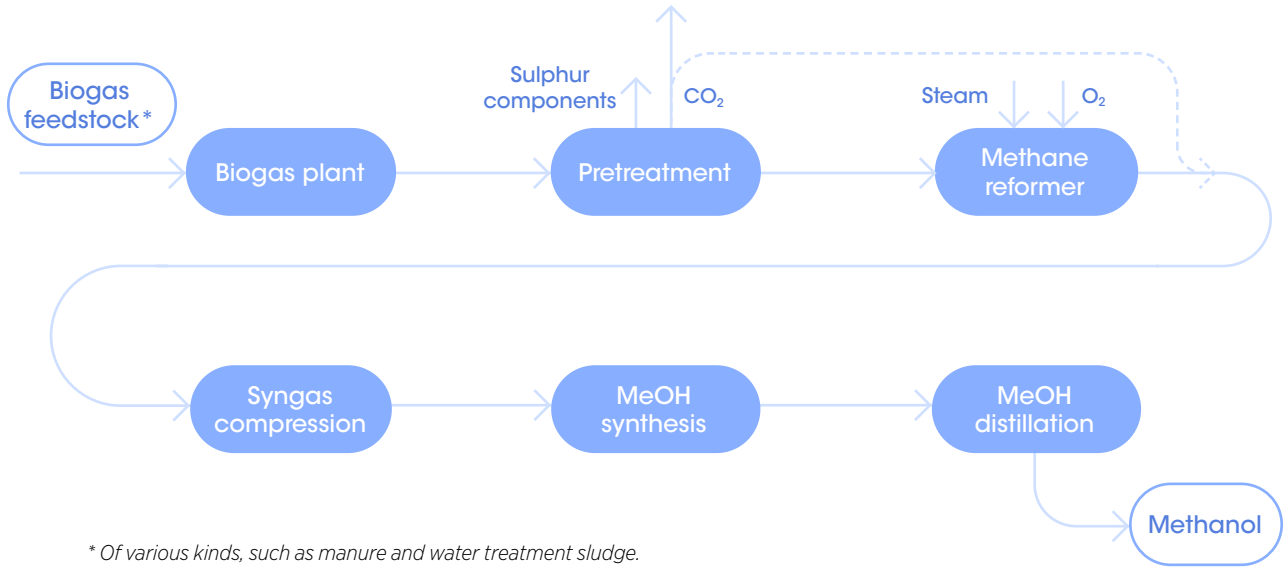
Technology	Feedstock	Project, reference	Project phase	Product	Plant capacity
Steam reforming	Natural gas/ biomethane	BASF, Ludwigshafen (DE)	Operational	Methanol	480 kt/y* (2018)
Steam reforming	Natural gas/ biomethane	OCI/BioMCN Groningen (NL)	Operational	Methanol	60 kt/y** (2017)
Steam reforming	Natural gas/ biomethane	OCI Beaumont Texas (US)	Operational	Methanol	1 075 kt/y (2020)***

** Plant capacity (Saygin and Gielen, forthcoming). Bio-methanol share is around 15%.*

*** Bio-methanol part (Compagne, 2017).*

**** Plant capacity (OCI, 2020). Bio-methanol share not given.*

Figure 22. Reformer-based methanol plant – general scheme



** Of various kinds, such as manure and water treatment sludge.*

Bio-methanol from the pulping cycle in pulp mills

When wood pulp is converted into pulp for further processing into various qualities of paper, raw methanol is formed in the digester where wood chips react with the cooking chemicals (mostly sodium hydroxide and sodium sulphide). The degree of production depends on the type of wood and the nature of the cooking cycle (Zhu et al., 2000). The methanol by-product contains various impurities and in almost all mills is used as an internal fuel for heat and power. It can, however, be treated and upgraded into saleable chemical-grade bio-methanol.

Recently (Q2, 2020), a large mill in Sweden started up such a plant, the world's first unit to produce grade AA methanol from this type of source (Södra, 2020a). Its production capacity is 5 250 t/y. Södra claims 98% GHG reduction for their new methanol product.

Table 6. By-product bio-methanol from wood pulping

Technology	Feedstock	Project	Project phase	Product	Plant capacity
Andritz	By-product from wood pulping	Södra Mill, Mönsterås (SE)	Operational	Bio-methanol	5.25 kt/y
Not known	By-product from wood pulping	Alberta Pacific (CA)	Operational	Bio-methanol	3 kt/y

Alberta Pacific has produced purified methanol for internal bleaching purposes at its Boyle Mill, Alberta, since 2012. Recently, California-based Oberon Fuels was awarded a USD 2.9 million grant from the California Energy Commission to support the upgrade of its DME production facility to double its current capacity to 17 000 L of renewable DME per day, and to test renewable methanol from a pulp mill as feedstock. The methanol will be supplied by Alberta Pacific (Oberon Fuels, 2020).

For this report a review of all pulp mills in Europe was undertaken using Eurostat data, starting in 2016 and taking into account the feedstock and pulping cycle. It concluded that approximately 220 000 t/y of methanol could be produced using the method applied by Södra.

If prorated using global pulp production, that would lead to a potential production capacity of 1.1-1.2 Mt/y of methanol. This number is on the low side because wood pulping globally is based more on hardwood compared to Europe, which utilises more softwood. The pulping of hardwood generates more methanol per tonne of pulp than softwood pulping.

Methanol from CO_2 (e-methanol)

E-methanol is a liquid product easily obtainable from CO_2 and green hydrogen through a one-step catalytic process. Produced through a Power-to-X technology, e-methanol is considered an electrofuel (e-fuel) and electrochemical. The difference between green hydrogen and other types of hydrogen is illustrated in Figure 23. Currently, most hydrogen is still produced from fossil fuels (brown and grey hydrogen). About 48%, 30% and 18% is produced from natural gas, oil and coal, respectively (IRENA, 2018). Only about 4% of hydrogen is obtained by electrolysis using either electric power from the grid or a renewable source (green hydrogen). Hydrogen is currently used by a diverse range of industries, including the chemical (for methanol, ammonia and polymers), refining (for hydrocracking and hydrotreating), metal processing, aerospace, glass and food industries. Interest in green hydrogen as a renewable fuel is also growing.

There are a number of ways to produce e-methanol through electrochemical processes (Figure 24). The simplest and most mature method is to make hydrogen through the electrolysis of water using renewable electricity,

Figure 23. Types of hydrogen according to production process

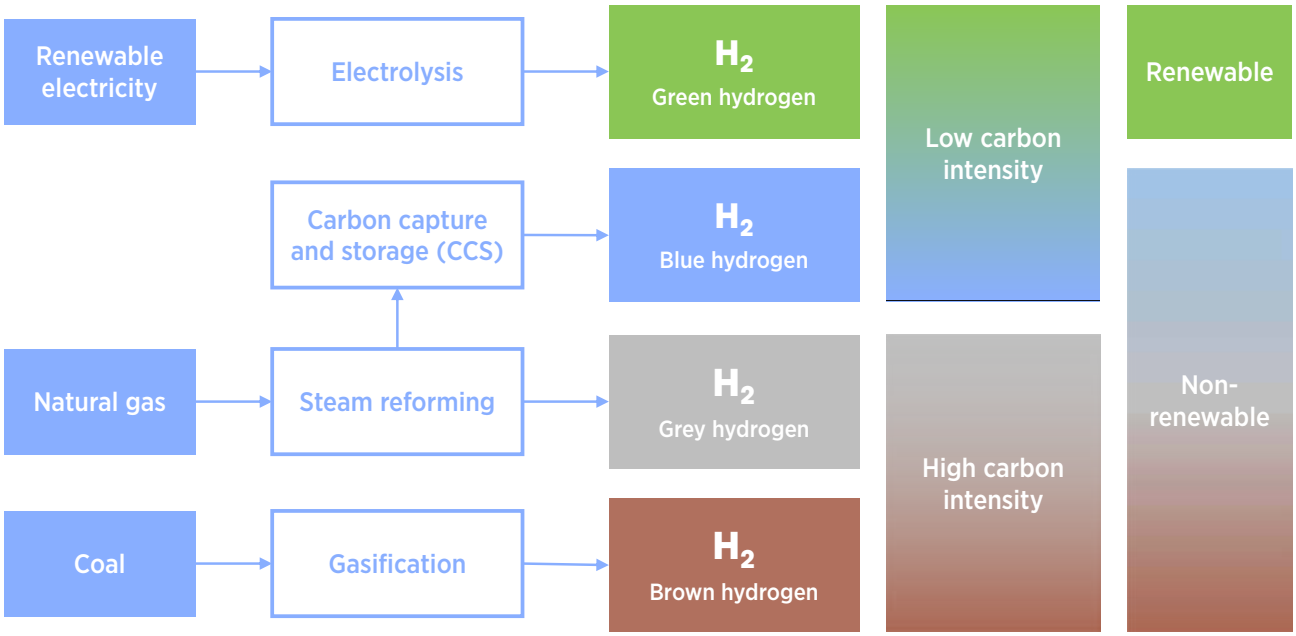
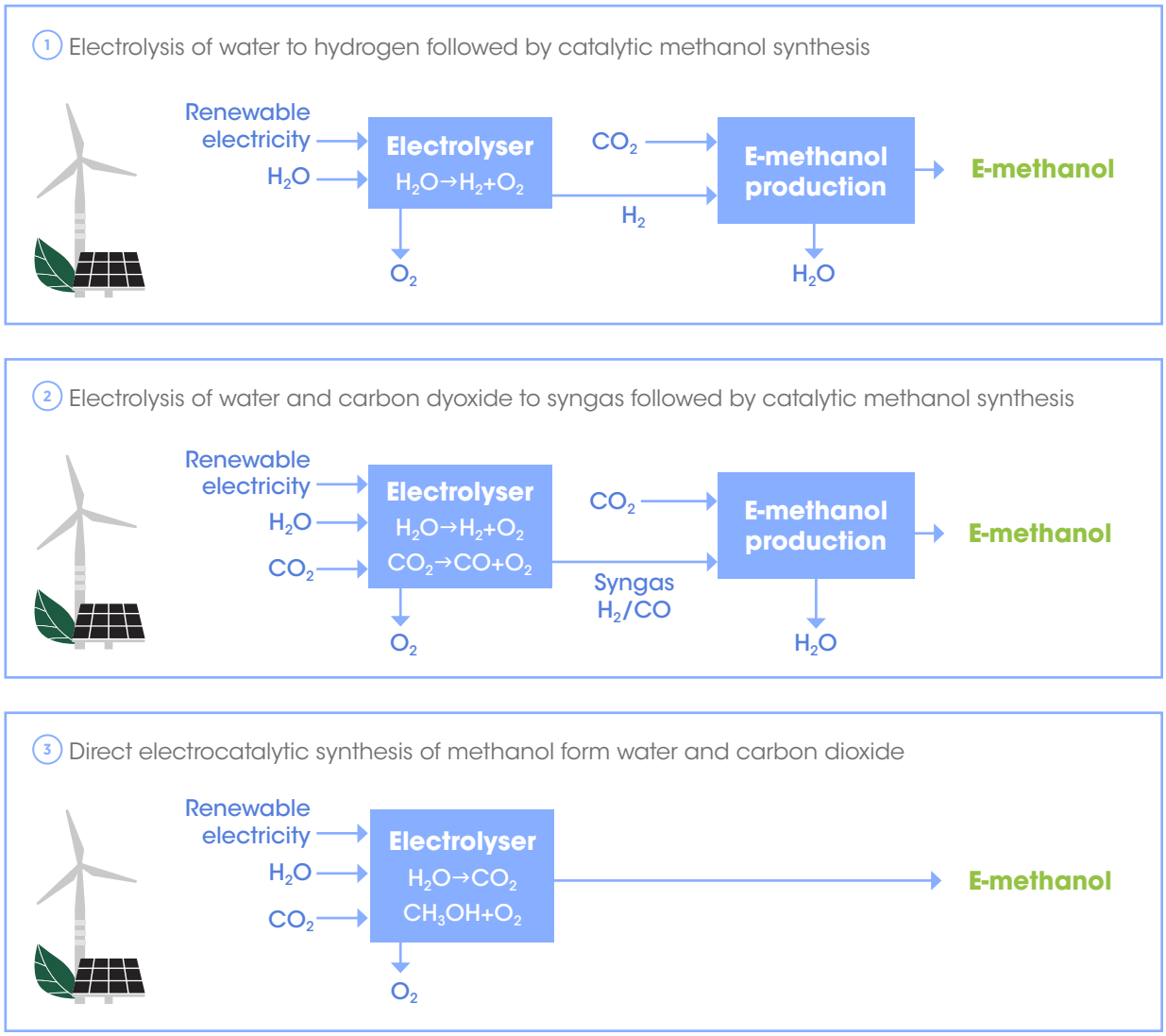


Figure 24. Approaches to e-methanol production through electrolysis and electrochemical processes



Source: *Ellis et al. (2019).*

followed by catalytic reaction with CO_2 to form e-methanol. Another approach is to produce both components of syngas, CO and H_2, through electrolysis, followed by conversion of the syngas to e-methanol as practised for conventional methanol production. While this route could achieve a higher conversion efficiency, it is less developed than water electrolysis (conventional water electrolysis is in the megawatt range, while this co-electrolysis route is at the lab, kilowatt scale). Direct electrochemical conversion of CO_2 and water to methanol is also being studied, but so far only limited efficiency and yield have been achieved at a laboratory scale (Goeppert et al., 2014; Olah et al., 2018).

Because the reaction of CO_2 with H_2 from water electrolysis is currently the only practical method to produce e-methanol, the following discussion focuses on that method.

In general, each molecule of CO_2 entering the process will exit as a methanol molecule. However, each CO_2 molecule requires three molecules of hydrogen and

will produce one molecule of water for each molecule of methanol. Accordingly, to produce one tonne of methanol, about 1.38 t of CO_2 and 0.19 t of hydrogen (~1.7 t of water) are needed. About 10-11 MWh of electricity are required to produce one tonne of e-methanol; most of it for the electrolysis of water (assuming CO_2 is provided). With a 100 MW electrolyser, about 225 t/d of e-methanol could be produced. Such electrolysers, although large, are already available from Thyssenkrupp (Thyssenkrupp, 2020a). For a large 1 000 t/d e-methanol plant, an electrolyser of at least about 420 MW would be necessary. To replace a conventional mega-methanol plant with production capacity of 2 500 t/d, an electrolyser in the gigawatt range would be needed. Production capacity for such large electrolysers still needs to be developed.

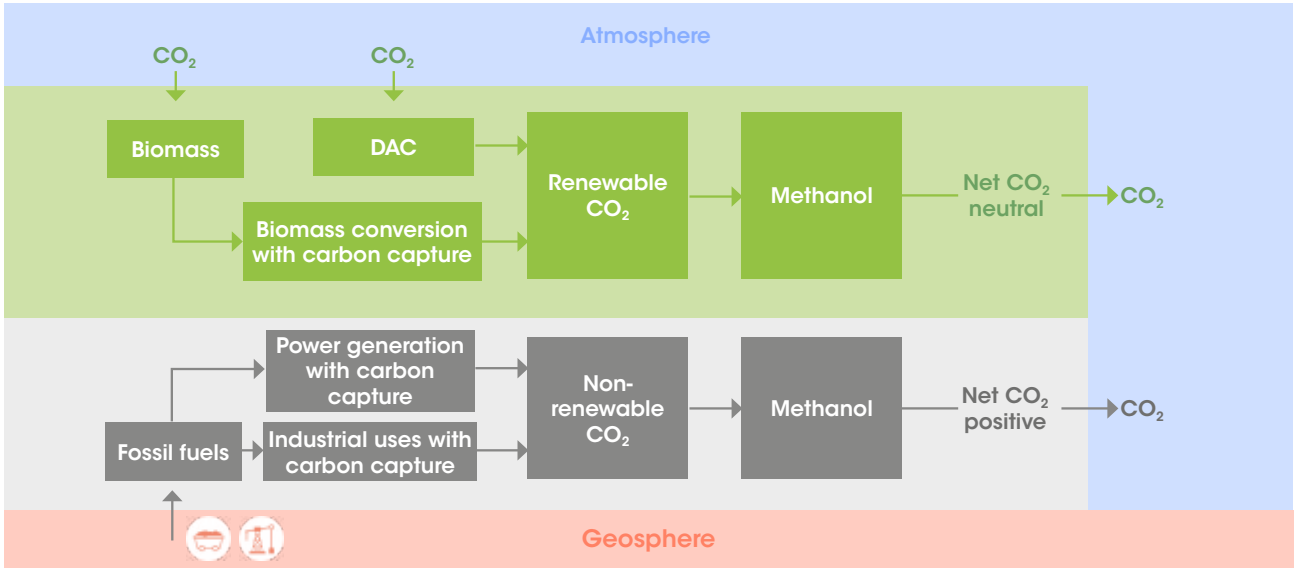
The technology for the e-methanol synthesis step is very similar to the one for the production of methanol from fossil fuel-based syngas and is therefore mature (TRL 8-9). The traditional CuO/ZnO/Al2O3 catalyst used has only to be slightly modified to accommodate the generation of larger amounts of water during synthesis of e-methanol. Such catalysts are already available commercially from a number of vendors including Haldor Topsoe, Johnson Matthey and Clariant. The reaction is operated at temperatures between 200°C and 300°C and pressures of 50-100 bar. Catalysts able to operate under milder conditions are also under development.

Carbon dioxide feedstock: The CO_2 feedstock for e-methanol production can be divided into two broad categories depending on its origin (Figure 25):

- **CO_2 from various industrial sources, including power plants, and steel and cement factories.** In this instance, the CO_2 would most likely come from the burning of fossil fuels. Even though recycled, it would still amount to fossil-based CO_2, which is non-renewable and makes the overall process net CO_2 positive. However, given that the CO_2 from these sources would otherwise be released into the atmosphere, using it one more time for the production of methanol with green hydrogen would result in a low-carbon methanol.

- **CO_2 obtained from the atmosphere either directly by direct air capture (DAC) or through biomass.** To be renewable, sustainable and net CO_2 neutral, biogenic sources of CO_2 will increasingly have to be used, such as from distilleries, fermentation units, MSW, biogas and other units such as power plants that produce electricity by burning biomass. These sources of CO_2 are normally treated as off-gases and therefore emitted to the atmosphere (usually at high CO_2 concentrations but atmospheric pressure). When the CO_2 from these units is captured either for storage or utilisation, the process is usually referred to as bio-energy with carbon capture and storage (BECCS)

Figure 25. CO_2 feedstock for the production of e-methanol



or bio-energy with carbon capture and utilisation (BECCU) (Consoli, 2019). Combining e-methanol and bio-methanol production in a single BECCU plant offers a number of advantages further described in this report's section entitled "Combination of bio- and e-methanol production". To complement photosynthetic CO_2 capture from air in biomass, anthropogenic CO_2 capture from the atmosphere is also becoming a possibility as technologies for DAC are now being developed and commercialised (Goeppert et al., 2014; Sanz-Pérez et al., 2016). BECCS, BECCU and DAC allow for a net carbon-neutral cycle in the production of e-methanol.

Hydrogen feedstock: The electrolysis of water to produce hydrogen has taken off in recent years to grow in scale from kilowatts to gigawatts using existing and well-established technologies. However, further electrolyser technology improvements and cost reductions are required to enable the mass production of cost-competitive green hydrogen (IRENA, 2020c). The electricity needed for the process can be generated by any form of energy. However, to be sustainable it needs to come from renewable sources. For the large-scale deployment of sustainable electrolysis, wind and solar PV have the greatest potential due to their increasing availability and decreasing costs. They are the world's fastest-growing sources of energy, providing clean and affordable electricity.

The first contemporary commercial CO_2-to-methanol recycling plant using locally available, cheap geothermal energy has been operated in Iceland by Carbon Recycling International (CRI) since 2011. This commercial demonstration plant, with a design from Johnson Matthey/Jacobs and an annual capacity of 4 000 t of methanol (~12 t/d), is based on the conversion of geothermal CO_2 and the readily available local geothermal energy (hot water and steam) sources (Figure 26) (CRI, 2020). The necessary H_2 is produced by water electrolysis using cheap geothermal electricity. Iceland embarked on this development as a means to exploit and possibly export its cheap and clean electrical energy. The produced methanol, called Vulcanol, is currently mixed with gasoline, used for biodiesel production and for waste-water denitrification.

In China, the Dalian Institute of Chemical Physics recently started operations at a 1 000 t/y e-methanol demonstration project (Figure 27) (AAAS, 2020). In this plant, the alkaline electrolysers for the production of the necessary hydrogen (1 000 normal cubic metres per hour of H_2) use the electricity produced by a 10 MW solar PV plant. After initial testing and ramping up, full operation is expected to start in October 2020. The project is the first to demonstrate the production methanol from solar power on an industrial scale.

Other e-methanol commercial plants are being planned around the world with production capacities ranging from 8 000 t/y to 180 000 t/y e-methanol (Table 7). If all the commercial projects in Table 7 come to fruition, in excess of 700 000 t/y of e-methanol capacity would be available. Plants from Liquid Wind in Sweden, ABEL in Australia, Swiss Liquid Future/Thyssenkrupp in Norway, and RH_2C in Canada will all use renewable H_2 and CO_2 from either industrial or biogenic sources (Swiss Liquid Future, 2020a; Liquid Wind, 2020; ABEL Energy, 2020; RH_2C, 2020). Other consortia are planning the construction of e-methanol plants in the ports of Antwerp and Ghent in Belgium, as well as in the Netherlands (Nouryon, 2020; aet, 2019; INOVYN, 2020). In Denmark, a sustainable fuel project aims to achieve electrolyser capacity of 10 MW in 2023, 250 MW in 2027, and 1.3 GW in 2030 respectively. The green hydrogen generated will be combined with CO_2 captured from the combustion of MSW or biomass to produce renewable methanol for maritime vessels and renewable jet fuel for planes (e-kerosene) (Maersk, 2020).

The recycling of both CO_2 and H_2 obtained as the by-products of industrial processes is also an option in some cases. In China, Henan Shuncheng Group/CRI recently started the construction of an emission-to-liquid plant that will convert H_2 from coke oven gas and CO_2 from a lime kiln to 110 000 t/y of methanol (CRI, 2020).

An increasing number of technology providers are also developing and licensing e-methanol solutions, including entire plants, e-methanol synthesis units, catalysts and larger electrolysers able to provide sufficient hydrogen. They include among others CRI, Thyssenkrupp/Swiss Liquid Future, bse engineering/BASF (FlexMethanol), Haldor Topsoe (eMethanol), and Johnson Matthey (HT, 2019a, bse engineering, 2019; CRI, 2020; JM, 2020, Thyssenkrupp, 2020b).

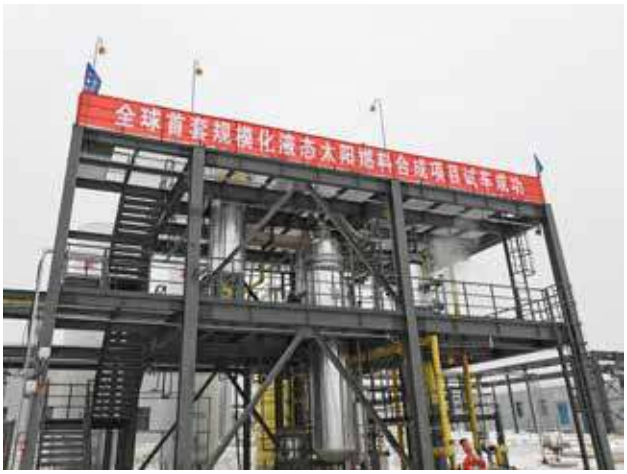
Numerous institutions, companies, universities and collaborative efforts are also developing CO_2-to-methanol technologies and testing them in

Figure 26. The "George Olah Renewable CO_2-to-Methanol Plant" of CRI in Iceland

Source: *CRI (2020).*

demonstration and pilot plants. In Aalborg, Denmark, the Power2Met project is producing about 800 litres per day (L/d) of e-methanol from biogas CO_2 and hydrogen obtained by the electrolysis of water using wind and solar energy (REintegrate, 2020; Energy Supply, 2020). Plans are to increase the capacity to about 10 000 m^3 per year by 2022 (Jensen, 2019). In Luleå, Sweden, the e-methanol technology developed by CRI was used to produce methanol from CO_2/CO and H_2 recovered from an industrial blast furnace at a steel manufacturing plant as part of the FresMe project under EU's Horizon 2020 programme (FReSMe, 2020). The necessary H_2 is complemented with H_2 obtained by the electrolysis of water. The two sources of H_2 enable maximum use of the current residual energy content of blast furnace gas for a methanol production capacity of up to 1 t/d from blast furnace gases. This project benefited from another EU-funded project entitled MefCO_2 aimed at improving the technology to produce methanol from CO_2 (MefCO_2, 2020). This test plant built in Germany had a capacity of 1 t/d of methanol from 1.5 t/d of CO_2 captured from the emissions of an RWE coal-fired power plant and 0.19 t/d of green hydrogen. On the same site a CO_2-to-DME process with a capacity of 50 L of DME per day is also being tested in the frame of the ALIGN-CCUS project (ALIGN-CCUS, 2020; Moser et al., 2018).

Figure 27. 1 000 t/y e-methanol demonstration plant in Lanzhou, Gansu Province, Northwestern China



Source: *Courtesy of Prof. Can Li from the Dalian Institute of Chemical Physics.*

As part of the Carbon2Chem project, a cross-industrial network funded by Germany, production of methanol from steel mill gases complemented by H_2 from water electrolysis will be studied at a Thyssenkrupp steel mill (Carbon2Chem, 2020). In Japan, Mitsui Chemicals operated for 4 500 hours a pilot plant with a 100 t/y methanol capacity, using CO_2 and H_2 with a catalyst developed by RITE (Mitsui Chemicals, 2009, 2010). In Korea, KIST developed the CAMERE process, an alternative two-step route from CO_2 to methanol (Joo et al., 2004). Zero Emission Fuels, a company in the Netherlands, is aiming to develop fully automated modular micro-plants to produce methanol from CO_2 captured from the air and renewable H_2 produced from solar power (ZEF, 2020). In Germany, a consortium of 30 partners named C3 Mobility is aiming to develop methods to produce renewable methanol from various feedstocks, and use this methanol as a fuel or platform chemical for the preparation of other transport fuels (DME, MTG etc.) (C3 Mobility, 2020).

Besides the electrolysis route to producing hydrogen, and subsequent conversion with CO_2 to methanol, some institutions and companies are also exploring other routes, such as high-temperature thermochemical conversion using solar heat or direct electrochemical conversion of CO_2 and water to e-methanol using direct sunlight (artificial photosynthesis concept [JCAP, 2020]). Synhelion, in Switzerland, uses high-temperature solar heat in excess of 1 000°C to convert CO_2 and water to CO and H_2 in a thermochemical process. The obtained syngas (H_2 + CO) can then be converted to methanol using standard methanol synthesis technology (Synhelion, 2020).

Besides methanol and DME, the production of oxymethylene ethers (OMEs) from CO2 and hydrogen is also being considered. OMEs are a diesel fuel substitute with a high cetane number, which burn soot-free and with very low pollutant emissions. The addition of OMEs to diesel fuel was also found to decrease significantly the PM and soot emissions (Lumpp et al., 2011; Wang et al., 2015). However, the production of e-OMEs was determined to be less energy-efficient than other e-fuels, including e-methanol and e-DME (Held et al., 2019, Kramer, 2018).

Table 7. Overview of existing or planned facilities and technology providers for e-methanol production

Country	Company	Start-up year	Capacity (t/y)	Product	Feedstock	Source
Iceland	CRI	2011	4 000	e-methanol (Vulcanol)	Geothermal CO_2 and H_2 from water electrolysis	CRI, 2020
China	Dalian Institute of Chemical Physics	2020	1 000	e-methanol	CO_2 and H_2 from water electrolysis (PV)	AAAS, 2020
Sweden	Liquid Wind	2023 (plan for 6 facilities by 2030)	45 000	e-methanol	Upcycled industrial CO_2 and H_2 from water electrolysis	Liquid Wind, 2020
Australia (Tasmania)	ABEL	2023	60 000	e-methanol	Biogenic CO_2 and H_2 from water electrolysis	ABEL Energy, 2020

China	Henan Shuncheng Group/CRI	2022	110 000	methanol[(a)]	CO_2 from limekiln and H_2 from coke oven gas	CRI, 2020
Norway	Swiss Liquid Future/ Thyssenkrupp	n/k	80 000	e-methanol	CO_2 from ferrosilicon plant and H_2 from water electrolysis (hydropower)	Swiss Liquid Future, 2020a, Swiss Liquid Future, 2020b
Norway	Consortium of companies/ CRI	2024	100 000	e-methanol	CO_2 and H_2 from water electrolysis	Stefánsson, 2019
Canada	Renewable Hydrogen Canada (RH_2C)	n/k	120 000	e-methanol	CO_2 and H_2 from water electrolysis (hydro)	RH_2C, 2020
Belgium	Consortium at the port of Antwerp	n/k	8 000	e-methanol	CO_2 and H_2 from water electrolysis	INOVYN, 2020
Belgium	Consortium at the port of Ghent	n/k	46 000-180 000	e-methanol	Industrial CO_2 and H_2 from water electrolysis	aet, 2019
The Netherlands	Consortium Nouryon/ Gasunie/ BioMCN and 3 others	n/k	15 000	e-methanol	CO_2 and H_2 from water electrolysis	Nouryon, 2020
Germany	Dow	n/k	~ 200 000	e-methanol	CO_2 and H_2 from water electrolysis	Schmidt, 2020
Denmark	Consortium of companies	2023-2030	n/k	e-methanol	CO_2 from MSW and biomass. H_2 from water electrolysis (offshore wind). Up to 1.3 GW electrolyser capacity by 2030	Maersk, 2020
Germany	Consortium	n/k	n/k	e-methanol	CO_2 from cement plant and H_2 from water electrolysis (wind)	Westküste 100, 2020

Technology demonstration plants (past and current)						
Country	**Company**	**Start-up year**	**Capacity**	**Product**	**Feedstock**	**Source**
Sweden	FreSMe	2019	1 t/d	e-methanol [(b)]	CO_2 and H_2 waste stream from steel manufacturing and H_2 from water electrolysis	FReSMe, 2020
Germany	MefCO_2	2019	1 t/d	e-methanol	Power plant flue gas CO_2 and H_2 from water electrolysis	MefCO_2, 2020
Denmark	Power2Met Danish Consortium	2019	800 L/d	e-methanol	CO_2 from biogas and H_2 from water electrolysis (wind and solar)	REintegrate, 2020
Germany	Carbon2Chem	2020	50 L/d	e-methanol [(b)]	CO_2/CO/H_2 from steel mill gases and H_2 from water electrolysis	Carbon2Chem, 2020
Germany	ALIGN-CCUS Project DME from CO_2	2020	50 L/d	e-DME	CO_2 from power plant flue gas and H_2 from water electrolysis	ALIGN-CCUS, 2020
Switzerland	Swiss Liquid Future	2012	75 L/d	e-methanol	CO_2 and H_2 from water electrolysis	Swiss Liquid Future, 2020a
Germany	Total/Sunfire e-CO_2Met project	2022	1.5 t/d	e-methanol	CO_2 from a refinery and H_2 from water electrolysis	Total, 2020
Germany	Bse Engineering / Institute for Renewable Energy Systems (IRES)	2020	28 L/d	e-methanol	CO_2 and H_2 from water electrolysis (wind)	bse Engineering, 2020
Japan	Mitsui	2009	100 t/y	e-methanol	CO_2 and H_2 from water electrolysis	Mitsui Chemicals, 2009, 2010
Korea	Korean Institute of Science and Technology (KIST) / CAMERE process	2004	100 kg/d	e-methanol	CO_2 from power plant flue gas and H_2 from water electrolysis	Joo, 2004

Selected technology providers						
Iceland	CRI	Technology provider	50 000-100 000	e-methanol	CO_2 and H_2 from water electrolysis	CRI, 2020
Germany	Thyssenkrupp/ Uhde/Swiss Liquid Future	Technology provider	3 600-72 000	e-methanol	CO_2 and H_2 from water electrolysis	Thyssenkrupp, 2020a
Germany	Bse Engineering / BASF	Technology provider	8 200-16 400	e-methanol	CO_2 and H_2 from water electrolysis	bse Engineering, 2020
Denmark	Haldor Topsoe	Technology provider	Variable	e-methanol	CO_2 and H_2 from water electrolysis	HT, 2019a
United Kingdom	Johnson Matthey	Technology provider	Variable 100 000-1 700 000	e-methanol	CO_2 and H_2 from water electrolysis	JM, 2020

Notes: *(a) Hydrogen obtained from coke oven gas and not from water electrolysis.*
(b) Part of the hydrogen obtained from the waste stream of steel manufacturing.
n/k = not known.

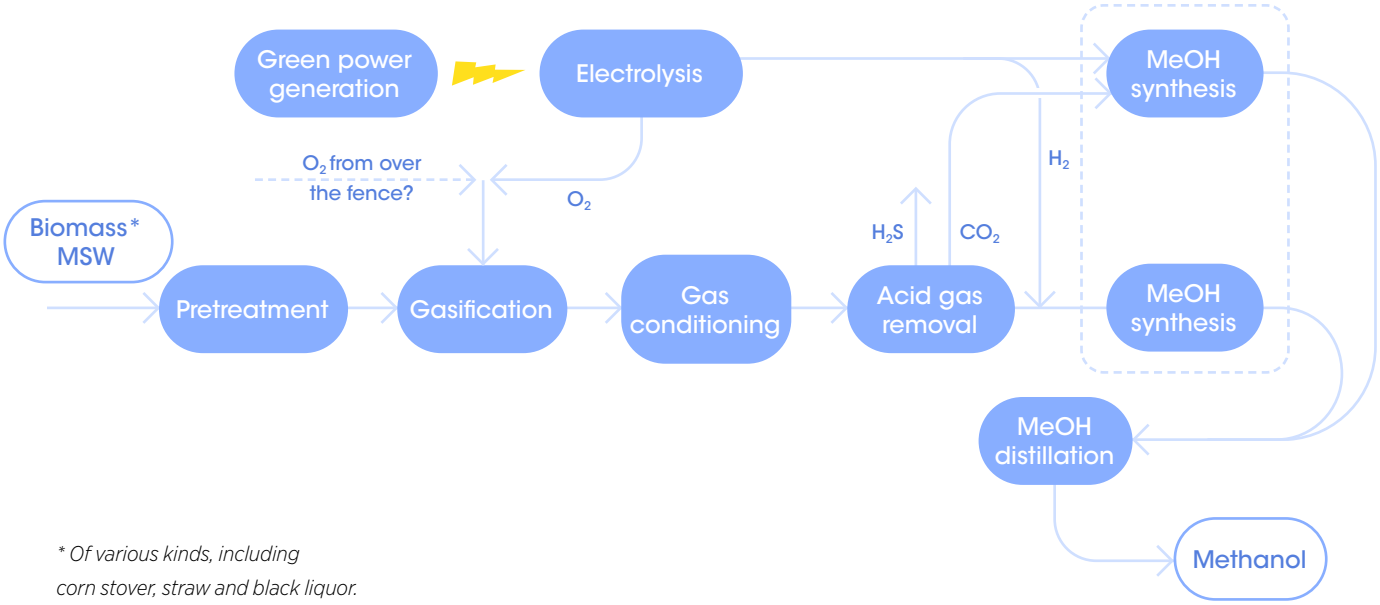
Combination of bio- and e-methanol production

The production of methanol from biomass is carried out in a similar way to its production from coal and heavy residual oil. CO_2 is generated in the gasifier due to the endothermic nature (energy-consuming) of the gasification reactions. In addition to that, due to their chemical composition, these feedstocks produce a syngas mixture with a low H_2/CO ratio. For methanol synthesis, the optimal H_2/CO ratio is close to 2. To adjust this ratio, part of the CO in the syngas is converted with water to H_2 through the WGS reaction. This also creates excess CO_2, which is separated and generally simply vented to the atmosphere. Because the production of methanol from biomass generates a lot of CO_2, the apparent conversion rate of biomass into methanol is reduced (Reschetilowski, 2013). The overall carbon efficiency in this type of scheme is around 50%, meaning that only about 50% of the carbon in the feedstock ends up in methanol; the rest is in the emitted CO_2.

An attractive possibility to increase the carbon utilisation rate is to react the normally emitted CO_2 with hydrogen from some other source to produce more methanol (Specht et al., 1999). This can be achieved by combining the bio-methanol scheme and part of the e-methanol scheme into a hybrid process where nearly 100% of the carbon in the biomass ends up as carbon in the methanol product, as illustrated in Figure 28. The hydrogen is provided by water electrolysis using renewable power. The elimination of CO_2 emissions, or in other words the use of all available bio-carbon, can take place in two steps. The first includes injection of hydrogen to accomplish a H_2/CO ratio of about 2, thus eliminating the need for the WGS. The second step is to inject enough H_2 to react the remaining CO_2 to methanol. Figure 28 illustrates this two-step process conducted in two separate methanol synthesis units, after which the two raw methanol streams are combined for downstream processing.

Commercially proven catalysts are available for both methanol synthesis from H_2/CO and from H_2/CO_2. Catalyst providers have also developed alternatives to this approach and shown that CO, CO_2 and H_2 can be combined into the same synthesis unit and still keep the efficiency of the conversion at a high level (Bertau et al.,

Figure 28. Combined bio- and e-methanol scheme with biomass or MSW as feedstock



** Of various kinds, including corn stover, straw and black liquor.*

2014). In such a case, the two methanol synthesis units inside the dashed rectangle in Figure 28 are combined into one, and the AGR unit becomes a cleaning unit only for sulphur components and other contaminants. CO_2 is left in the main syngas stream.

Elimination of the WGS unit has a number of direct advantages such as:

- No investment in a WGS unit.
- No high-pressure steam injection into the syngas needed for the WGS reaction.
- No loss of boiler feed water (reaction water) in the WGS.
- No loss of green carbon due to CO becoming CO_2 in the WGS unit.
- No loss of syngas energy (normally 3-5% loss) in the exothermic WGS reaction.
- Increased syngas production in the order of 45-55% compared to the case with a WGS unit (depending on H_2/CO ratio in the raw syngas upstream WGS).
- Lower operating cost for the gas-cleaning plant due to lower CO_2 load.
- Lower relative investment in the syngas and methanol generation parts of the plant due to economies of scale. The gasification plant will stay the same.

Hydrogen injection in this way does not have any foreseeable negative effects on the process. There are, however, some additional overall benefits to those already listed, such as

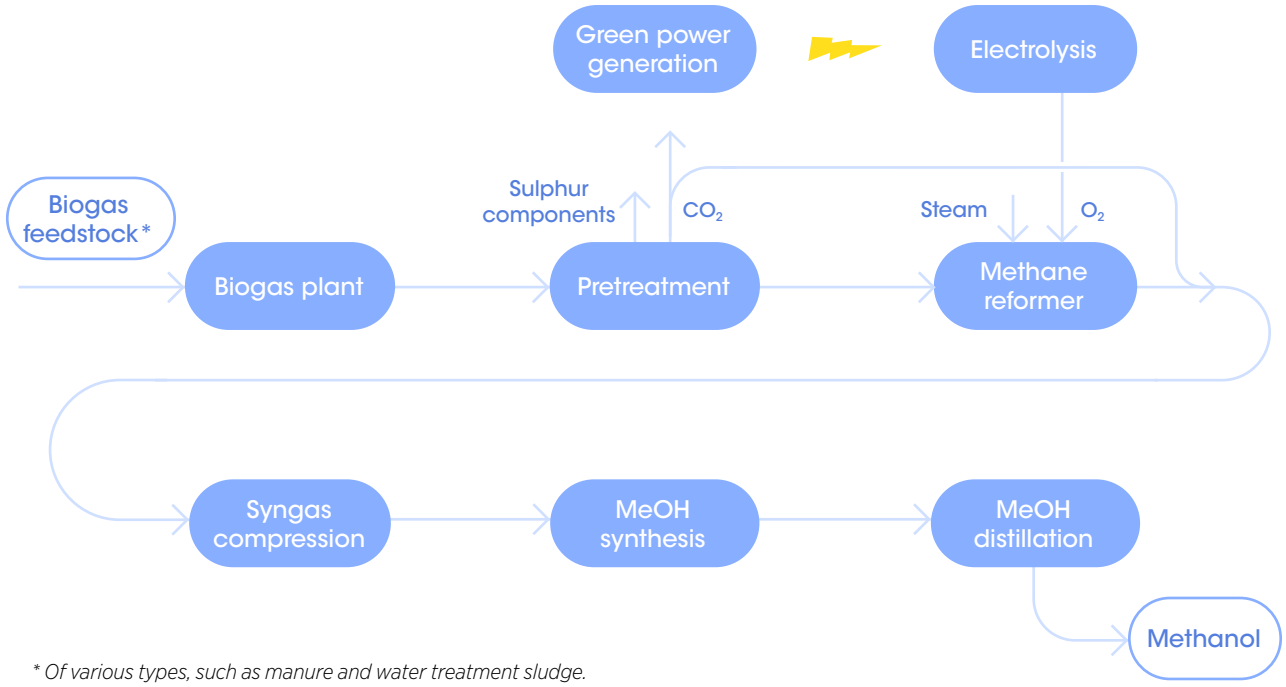
- The air separation unit may no longer be required (depends on the H_2/CO ratio in the raw syngas) because the oxygen produced by the electrolysis of water produces pure oxygen, which can replace O_2 from an air separation unit. The required investments are similar, and removing the air separation unit helps to offset the power needs of the electrolyser.
- All the CO_2 is easy to track and will come from a renewable source if biomass materials make up the feedstock.
- The CO_2 is already in situ in the plant, at pressure and ready to be synthesised with hydrogen to methanol.
- If for some reason CO_2 is separated in the AGR, as Figure 28 indicates, it is still at a high concentration and thus highly suited as feedstock for another "e-product" unit.

Combining the conventional bio-methanol process according to Figure 20 with e-methanol as described above allows for all the carbon in the biomass to be utilised, increasing the production potential from a given amount of biomass from around 60% to about 140%. Starting with 1 MWh of biomass results in 1.4 MWh of methanol. This, however, also requires the necessary renewable energy for the generation of H_2.

Analogous to the combination of solid biomass and electrolysis technologies shown in Figure 28, a methanol production scheme based on biogas is also possible. Figure 29 shows how CO_2 generated during biogas pretreatment can either (a) be part of the reactions in the reformer together with methane, steam and O2, or (b), depending on the required balance between the gases in the methane reformer, bypass the reformer and be added later in the process chain downstream of the methanol reformer. Additional H_2 is then needed to create an optimum gas composition for the methanol synthesis. A way to further decrease carbon emissions from the process would be to heat the reformer with renewable electricity, a process under development by, for example, Haldor Topsoe. In late 2020, Perstorp announced the plan to build the methanol plant using this technology in Stenungsund, Sweden under Project AIR. The plant aims to replace 200,000 tons of fossil methanol and start producing renewable methanol from 2025 (Perstorp, 2020).

With the previously mentioned process alterations being part of the process solution, virtually all carbon from the feedstock can end up as carbon in the produced methanol, resulting in a substantial increase in production capacity from a given amount of biogas. From a carbon utilisation point of view, it would be more efficient than the current use of biogas in power and heat generation or as a vehicle fuel in the form of biomethane.

Figure 29. Combined bio- and e-methanol scheme with biogas as feedstock



** Of various types, such as manure and water treatment sludge.*

3. PERFORMANCE AND SUSTAINABILITY

3.1.Performance and efficiency

Outside China, the world's methanol production uses natural gas as feedstock with a few exceptions where coal is utilised instead. Production from coal is overwhelmingly based in China. The overall energy conversion efficiency for a large, modern natural gas-based plant is around 70%. For coal to methanol the energy conversion efficiency is in the order of 50-60% depending on technology selection.

The performance of renewable methanol plants (amount of methanol produced in a given period, e.g. a year) depends on many factors, such as the plant set-up (e.g. feedstock, co-products, technology) and local conditions (e.g. brownfield or greenfield site, availability of feedstock or renewable electricity). Assessing real-life performance is difficult as only a limited number of commercial plants are currently in operation (Table 4 and Table 7). Different models based on various assumptions can be used to investigate different plant configurations in specific locations. This leads to a range of estimates for efficiency and environmental impact that are often difficult to compare.

Bio-methanol

There are still only a relatively limited number of commercial bio-methanol plants in operation (Table 4).

Nevertheless, a number of qualified actors have carried out a considerable amount of planning and front-end engineering for projects at an advanced stage of construction, and advanced demonstration plants have logged operational time resulting in a more secure base for upscaling. Gasification-based plants for methanol and other products like FT fuels are under construction.

A combination of input data from plants in operation, under construction and at an advanced stage of planning provide a more securely based set of data, offering a more accurate picture with respect to performance and efficiency. An approximate overall estimate of the conversion efficiency of a specific process route can be reached by multiplying the energy conversion efficiency of each process unit involved in the conversion chain.

Initially three units degrade the chemically bounded energy, and their respective energy efficiency can be multiplied together to reach an approximate overall conversion efficiency. Table 8 describes these three process operations.

Table 8. Energy conversion efficiencies for certain process units

Process operation	Energy efficiency	Comment
Gasification of feedstock	0.7-0.8(+)	The wide range depends on feedstock characteristics such as level of inerts and moisture, and overall gasifier temperature
WGS	0.95-0.97	The higher the H_2/CO ratio is in the feed gas, the less water-gas shifting is required, thus the lower the energy losses
Methanol synthesis	0.79-0.8	With a stoichiometric syngas and limited amount of inert gases
Overall	0.53-0.62	

Multiplying these three efficiency numbers leads to an overall conversion efficiency of 0.53 to 0.62. There may be a few percentage points to gain with further optimisation, especially in the gasification unit.

The calculated interval coincides well with all the data received from various technology providers and project developers. Around 60% overall energy conversion is typical for biomass conversion, while MSW conversion is at the lower end of the interval.

Biogas can replace natural gas in current methanol production plants based on fossil natural gas. After being upgraded to pipeline quality, biomethane can be part of the feedstock, as is done by BASF and BioMCN (BASF, 2018; BioMCN, 2020). Large sources of biogas upgraded and purified to clean biomethane and fed into a reformer-based methanol production process will have the same conversion efficiency as a corresponding natural gas-fed plant.

E-methanol

For the production of e-methanol the process is quite straightforward. Three main parts have to be considered: ① *H_2 generation by water electrolysis,* ② *CO_2 capture*, and ③ *methanol synthesis.*

① The electrolysis of water to hydrogen and oxygen is a mature technology with current efficiencies (higher heating value [HHV] of H_2) of roughly 75-85 % for alkaline and PEM-based electrolysers (IRENA, 2018). Alkaline electrolysers are the most common and are inexpensive. Modular units of 10 to 20 MW are available that can be combined to produce plants with sizes over 100 MW and a lifetime of over 30 years with 98% availability (Thyssenkrupp, 2020a). PEM-type electrolysers allow for a higher H_2 output pressure to be delivered (30 bar and higher), which could reduce the cost of pressurisation for the downstream methanol synthesis. However, these are more expensive than alkaline electrolysers (IRENA, 2020c). Solid oxide electrolysers are also being developed that could offer higher efficiency by operating at much higher temperatures (> 700°C). Some hydrogen storage capacity will also be needed to allow for continuous operation of the methanol synthesis unit. On a large scale, the production cost of renewable H_2 is mainly dictated by the cost of renewable electricity.

② Worldwide more than 37 billion tonnes of co_2 related to human activity are released into the atmosphere every year, of which 34 billion tonnes are energy-related (Olivier and Peters, 2019; IRENA, 2020b). These CO_2 emissions originate from electricity generation, cement and fermentation plants, industry, the transport sector, heating and cooling of buildings, and other activities. However, while sources of CO_2 are plentiful, sources of captured CO_2 that are currently available for recycling into fuels and material are not. The cost associated with capturing CO_2 depends greatly on its origin (Table 9). Facilities at which the capture of CO_2 is easiest are those that already produce concentrated streams of CO_2, such as natural gas purification and production of fertiliser and bio-ethanol (Irlam, 2017). However, the amount of CO_2 available from these plants is limited. Other sources with lower CO_2 concentrations include fossil fuel power plants (coal, natural gas, oil), iron and steel plants and cement production.

The removal and capture of CO_2 from gas streams can be achieved by a range of separation techniques depending on factors such as CO_2 concentration, pressure and temperature. These separation technologies are based on various physical and chemical processes, including absorption into a liquid solution system, adsorption onto a solid, cryogenic separation and permeation through membranes. The technologies for large-scale carbon capture from fossil fuel power plants and industrial processes are relatively mature, but have yet to be applied on the enormous scale needed for the Power-to-X sector. One has also to keep in mind that most of these sources are not renewable or sustainable sources of CO_2; they still rely on fossil fuels.

Biomass can provide some of the needed renewable CO_2 though BECCS and BECCU plants. Due to the ease of obtaining inexpensive high-purity CO_2, bio-ethanol production facilities currently represent most of the BECCS and BECCU units in operation (Consoli, 2019). However, as can be seen in Figure 30, which displays estimates for CO_2 capacity from various renewable sources, the amount of CO_2 available from these sources is limited (Olsson et al., 2020). Biogas, pulp and paper and waste-to-energy plants could also provide additional amounts of CO_2. Other technologies to capture CO_2 from large power plants producing electricity by burning biomass are under development as well. However, given the amounts of CO_2 required in the long run, CO_2 capture from the atmosphere will also have to be implemented.

So-called direct air capture (DAC) technologies are being developed by a number of companies, including Climeworks, Carbon Engineering and Global Thermostat (Sanz-Pérez et al., 2016; Goeppert et al., 2012). CO_2 capture from air is conducted at ambient temperature using various CO_2 sorbents. The captured CO_2 is then released in its concentrated form (up to 100%) by heating the sorbent to a temperature high enough to liberate the CO_2, which can then be used for methanol synthesis. Although DAC technologies are still relatively new (TRL ~4-7 depending on the technology), they are improving rapidly. DAC offers a number of advantages compared to point-source capture. Air offers an almost inexhaustible source of sustainable CO_2 that is available anywhere on earth. The DAC plants are thus independent of emission point sources and could be placed anywhere to allow the capture of CO_2.

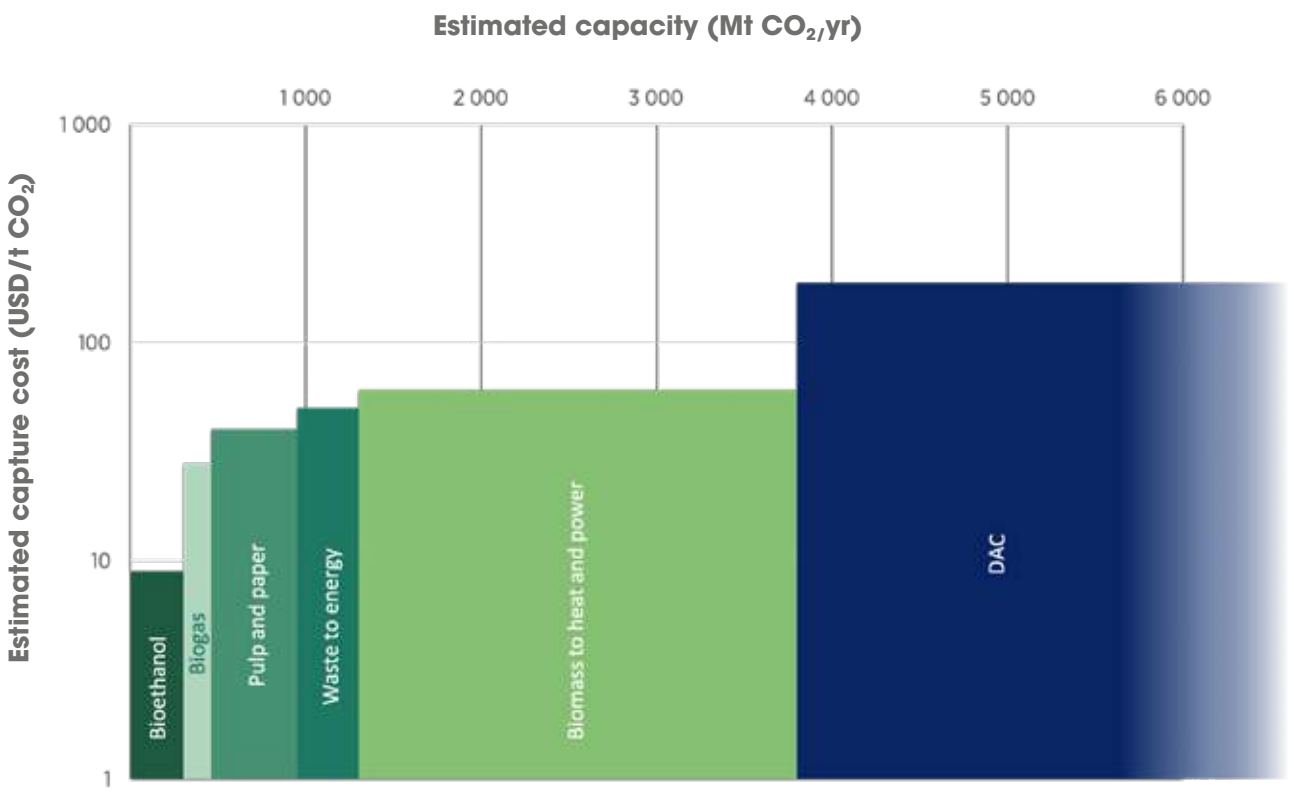
Looking at Figure 30, which displays a proposed estimate and distribution of global CO_2 availability, it would seem that the amounts of renewable CO_2 potentially available should allow the production of millions of tonnes of e-methanol per year. However, these are estimates of CO_2 availability for all uses, including CCS and CCU, and for all products such as e-fuels including e-methanol, e-kerosene and e-gasoline. E-methanol production is therefore likely to require the use of CO_2 from all available renewable sources, in an "all of the above" type approach, and not just the cheapest ones (bioethanol and biogas) for which there will be more competition and limited capacity. Ultimately, DAC offers greater potential. The situation with CO_2 resources and e-methanol is similar to the one for biomass and bio-methanol, for which there will likely be competition for the cheapest biomass feedstock.

Table 9. Selection of renewable and non-renewable sources of CO_2

Source or technology	CO_2 concentration in exhaust or gas stream (%)	CO_2 concentration after treatment (%)	
Biomass to ethanol	Up to 100	Up to 100	**Renewable CO_2**
Biomass combustion	3-8		
Biomass gasification	20-90		
Biogas	40-50		
BECCS/BECCU	Close to 100		
DAC*	0.042		
Coal power plant	12-14	Up to 100	**Non-renewable CO_2**
Coal power plant with oxy-combustion	Close to 100		
Natural gas power plant	3-5		
Iron and steel plant	20-30		
Cement plant	15-30		
Natural gas purification	2-65		
Ammonia synthesis	Up to 100		

** DAC produces renewable CO_2 only if powered by renewable energy.*

Figure 30. Example of estimates for global renewable CO_2 availability from different sources by the middle of the 21st century



Source: *Based on Olsson et al. (2020).*

③ The capital investment for a methanol synthesis unit using CO_2 and H_2 is estimated to be about the same as that for a conventional syngas-based plant. The technology to produce methanol is thus already mature and very similar to the one used in traditional fossil fuel-based plants. Overall, the plant will produce e-methanol with > 99% yield and selectivity. The reaction of CO_2 with hydrogen is exothermic (releases energy) and the heat of the reaction can be used to provide other plant services such as distillation. When relying on fluctuating renewable energy to produce the necessary H_2, some load-following capability for the methanol production unit would be advantageous, and also provide an important energy storage service for the power grid (CRI, 2020).

Compared to a conventional natural gas- or coal-based methanol plant, the very energy-demanding and costly reforming or gasification step is also eliminated, as is the generation of waste products from this step (sulphur, ash, NOx, PM, heavy metals, tars, etc.). In addition, the lower by-product content of methanol produced from CO_2 may simplify the methanol distillation step (Pontzen et al., 2011). The overall efficiency of methanol production from electricity and CO_2 is about 50-60%. This is largely due to the need to produce hydrogen through water electrolysis.

An economical option that could be used to gradually green the production of methanol would be to co-feed CO_2 and renewable H_2 into a traditional methanol fossil fuel-based plant. This would increase the know-how in CO_2 capture and renewable H_2 technologies and allow for a faster scale-up. Such an approach could also help to absorb some of the fluctuation and intermittency of renewable electricity.

The combination of bio- and e-methanol production in one site also offers clear synergetic advantages by proving a source of CO_2 for e-methanol production, and a hydrogen source for the complete conversion of the carbon contained in the biomass.

3.2. Renewable methanol vs alternatives

Methanol has a number of advantages compared to some other proposed renewable energy carriers, including hydrogen, CNG/LNG, ammonia and batteries (Table 10 and Figure 31). Hydrogen gas has been proposed as an energy storage medium and produces, besides energy, only water when combusted. In practice, however, because of its low volumetric density hydrogen requires either compression to high pressures (350-700 bar) or liquefaction at very low temperature (-253°C), making its storage problematic and energy-intensive. It is also highly flammable and explosive and can diffuse through many commonly used metals and materials.

The infrastructure needed to transport, store and dispense hydrogen safely would therefore be very expensive. LNG too requires cryogenic temperatures for its storage (-162°C). If the space for the containment is included in the comparison, the energy density of methanol is comparable to that of LNG. Liquid ammonia has either to be cooled down to -34°C or kept under moderate pressure. Methanol, on the other hand, does not need any refrigeration or pressurisation because it is a liquid under ambient conditions.

The volumetric energy density of methanol is only about half that of gasoline and diesel, but about three times higher than compressed H_2 (700 bar) and two times higher than liquid H_2. One litre of methanol actually contains more hydrogen than one litre of liquefied H_2. An often-proposed purely hydrogen-based economy would require massive investment, and the construction of a costly and specialised infrastructure that does not exist presently. As a liquid fuel, methanol is relatively easy to handle and does not need highly specialised equipment for its transport, storage and distribution. With minor and inexpensive modifications, the current infrastructure can be adapted to methanol, enabling a smooth transition to the use of renewable methanol. Renewables-based gasoline and diesel equivalents can also be produced, but the process is more complicated and the energetic cost higher than for renewable methanol (Kramer, 2018). Methanol itself can be converted to gasoline through the well-developed methanol-to-gasoline process (MTG) (IRENA, 2016a). However, the problems associated with gasoline and diesel fuels such as PM, NOx and hydrocarbon emissions would also remain.

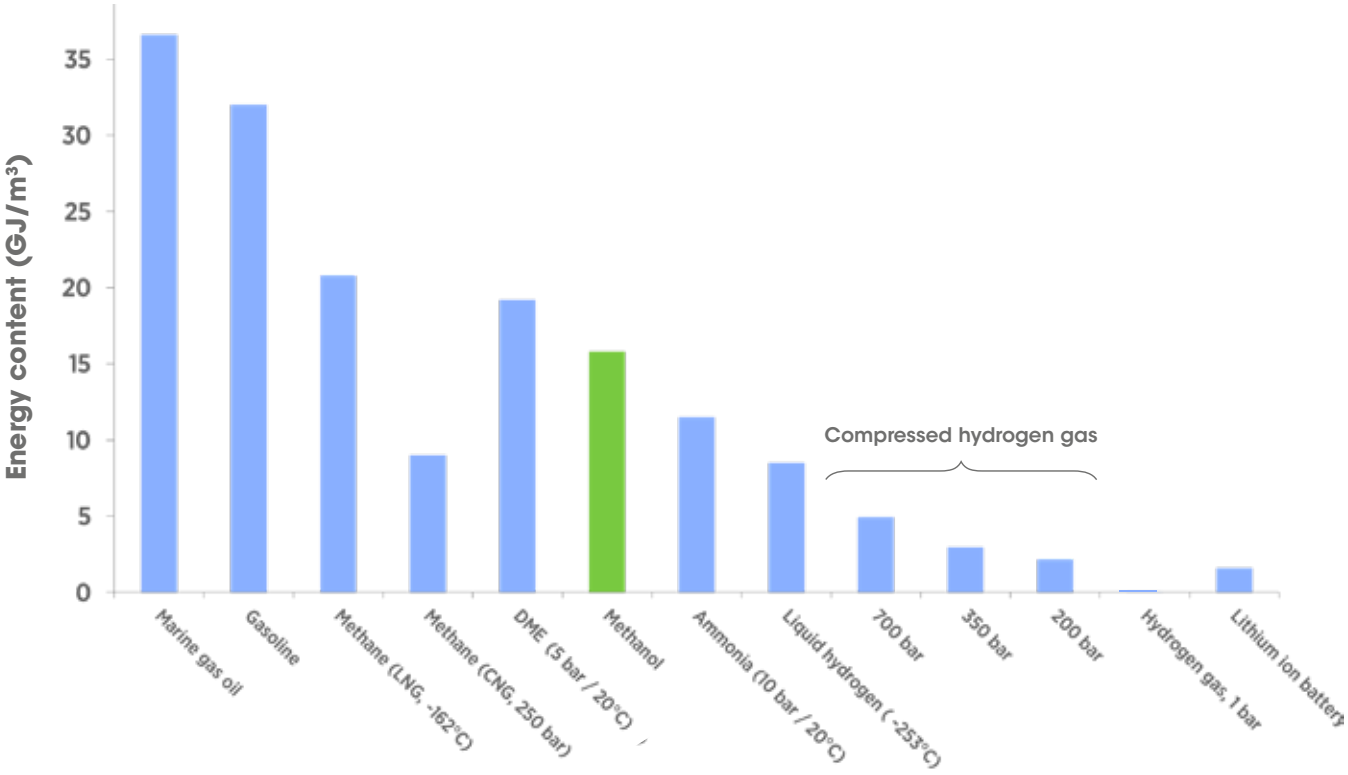
While methanol can already be widely used today in conventional ICEs, it can also act as a fuel for advanced hybrid (methanol/electric) and FCVs. In that case

Table 10. Comparison of various fuel properties

Fuel type	LHV (MJ/kg)	Volumetric energy density (GJ/m³)	Storage pressure (bar)	Storage temperature (°C)
Methanol	19.9	15.8	1	20
DME	28.9	19.2	5	20
LNG	48.6	20.8	1	-162
CNG	48.6	9	250	20
Liquid ammonia	18.6	11.5	1–10	-34 (at 1 bar)–20 (at 10 bar)
Liquid hydrogen	120	8.5	1	-253
Compressed hydrogen	120	4.7	700	20
Gasoline	43.4	32	1	20
Marine gas oil	42.8	36.6	1	20
Lithium ion battery	0.4-1	0.9-2.4	1	20

Notes: *LHV = lower heating value; GJ = gigajoule; MJ = megajoule.*

Figure 31. Volumetric energy content of various fuels



methanol is reformed to hydrogen on board a vehicle; it is then fed to a fuel cell to charge batteries in an EV, or to provide direct propulsion in an FCV. In this case too, the use of liquid methanol avoids the need for on-board systems able to store hydrogen safely gas under high pressure (350-700 bar) in FCVs. To date, methanol is the only liquid fuel that has been demonstrated on a practical scale in fuel cell-based transport applications. An added benefit of using methanol is that the same fuel can power both conventional ICE vehicles and FCVs, leading to a seamless transition to these more advanced powertrains.

Batteries are already being used for applications in the transport sector. Most of the current progress on battery vehicles is for passenger cars and light-duty vehicles. As battery technology continues to develop with improved performance and energy density, car manufacturers are already introducing into the market battery-powered buses and heavy-duty trucks. In the shipping sector, some applications of electric ferries are available, and in the aviation sector small electric aircraft for short-haul flights. However, electrification of long-distance maritime shipping and aviation with existing battery technology seems to be more challenging. For those applications, bio- and electro-fuels could play an important role (Moser et al., 2018; IRENA, 2018).

The Research Association for Combustion Engines (FVV) has conducted a study of e-fuels' potential in Germany. It determined that the e-fuels offering the lowest mobility cost for cars and trucks were e-methanol, e-DME and e-methane (Kramer, 2018). FT fuels, H_2 and even battery electric mobility costs were all higher. The cost calculations included the production of the fuel, distribution infrastructure, vehicle cost, etc. However, the result depends on the availability of cheap feedstock such as biomass, green hydrogen and renewable CO_2. Another study identified that e-fuels would be suitable only for sectors such as aviation and shipping where no alternatives are available due to the lower overall efficiency when used in a car or trucks (Calvo Ambel, 2017; Malins, 2017).

Methanol, as with any other alternative fuel or chemical, also has drawbacks. Like gasoline, ethanol and hydrogen, methanol is highly flammable and can lead to explosions

if stored or handled improperly. Methanol is also toxic and can be lethal if ingested. It can absorb moisture from the atmosphere, which can lead so phase separation in methanol/gasoline blends. Methanol is corrosive to some metals and is incompatible with some plastics, resins and rubber. Thus, compatible metals, plastics and elastomer materials should always be selected (details about the pros and cons of methanol can be found in Annex 1).

3.3. Emissions and sustainability

Emissions

A main advantage of biomass- and CO_2-based methanol production is the reduction in overall CO_2 GHG emissions. For a complete life-cycle analysis (LCA), also called cradle-to-grave analysis, all steps of methanol production, distribution and use have to be taken into account, addressing the environmental impacts of each of these steps, including GHG emissions, other pollutant emissions (NOx, CO, particulates, SOx, etc.) and water use. These depend on a large number of parameters including the nature of the feedstocks, by-product generation, processes applied, how the product is used, and so on. This makes the determination of an actual set of numbers to compare with the overall environmental impact of other fuels and feedstock somewhat challenging. Nevertheless, such analyses will be increasingly needed to assess the environmental impact of various fuels/materials and processes.

The industrial sector, currently accounting for about a third of global CO_2 emissions, has been identified as one of the areas that will be challenging to decarbonise/defossilise (IRENA, 2020b). In the chemical/petrochemical subsectors relevant to methanol and its derived products, improvements in energy efficiency, electrification and replacing fossil energy input with renewable energy can greatly reduce the carbon intensity of their processes. In that context, electric reforming of natural gas to produce LCM is one option. However, to go further, the chemicals and materials produced need to be themselves progressively defossilised through the use of renewable feedstocks (green hydrogen, renewable CO_2, biomass, etc.). This should allow related CO_2 emissions to decrease over time to eventually reach net-zero emissions by the end of the century. By following this greening path, methanol and all the chemicals and materials derived from it (including formaldehyde, DME, MTBE, acetic acid, plastic, solvents) would thus become carbon neutral. Of course, levels of CO_2 and other emissions would have to be verified by rigorous LCAs for all of these processes.

In the transport sector numerous studies have been conducted to determine the level of emissions of various fuels. So called well-to-wheel (WTW) analyses, in particular for the use of methanol, DME and other fuels, have been performed and generally focus on GHG emissions and overall energy efficiency of the fuel pathways. The WTW analysis itself can be divided in two individual steps: well-to-tank (WTT) and tank-to-wheel (TTW) analysis. The WTT focuses on the extraction of the raw materials, production of the fuel and its distribution to the vehicle. The TTW accounts for the utilisation of the fuel in the vehicle, i.e. the conversion of the chemical energy contained in the fuel to kinetic energy in the power train.

Relative to conventional fuels on a WTT basis, producers estimate that renewable methanol offers carbon reduction benefits ranging from 65% to 95% (Law et al., 2013). These GHG benefits were among the highest for alternative fuels that can displace gasoline and diesel. For the TTW portion of the full fuel cycle, methanol as a transport fuel can also offer advantages. Methanol has a higher octane number than gasoline (RON+MON average of 100),[1] allowing higher compression ratios that result in more efficient use of energy in an appropriate engine, translating into lower tailpipe emissions of CO_2 for the same power output. Methanol/gasoline blends also have considerably higher octane numbers than gasoline alone and were found to reduce CO_2 emissions as well (Sileghem et al., 2014; Turner and Pearson, 2011).

Furthermore, methanol is cleaner burning than regular gasoline, reducing the emission of other pollutants (PM, NOx, SOx). Methanol can also be used in diesel engines equipped with glow plugs and newly developed "methanol engines", and even more advanced vehicles propelled by fuel cells, reducing further the tailpipe emissions (Olah et al., 2018, Schröder et al., 2020). When used as a marine fuel, the SOx, PM and NOx emissions decreased by more than 99%, 95% and

1 RON = research octane number; MON = motor octane number.

60-80%, respectively, compared to fuel oil (Dolan, 2020; MI, 2020b; Andersson and Márquez Salazar, 2015; DNV GL, 2016). Comparing various biomass sources for the production of methanol, it was determined that the WTW CO_2 equivalent emissions of black liquor were 3-12 g CO_2-eq/MJ, wood waste were 5.3-22.6 g CO_2-eq/MJ, and farmed wood (wood obtained from tree plantations) were 4.6-16.5 g CO_2-eq/MJ. The results depended on the studies as shown in Table 11 and Figure 32 (see also Schröder et al., 2020), and do not include land use change or indirect land use change GHG emissions.

Methanol from crude glycerine and biogas had somewhat higher emissions, at 30.6 g CO_2-eq/MJ and 30-34.4 g CO_2-eq/MJ, respectively. The WTW CO_2 emissions of methanol from CO_2 recycling and H_2 from renewable sources was estimated at 1.74-33.1 g CO_2-eq/MJ, depending on various assumptions. Compared to a reference fossil fuel emission of 83.8 g CO_2-eq/MJ for gasoline (EU, 2009), this is a substantial decrease. Vulcanol, produced from geothermal CO_2 and green hydrogen and sold by CRI, lowers GHG emissions by up to 90% compared to gasoline (CRI, 2020). Methanol from black liquor and farmed wood reduced WTW CO_2 emissions by up to 96% and 95%, respectively. Using the GREET model, a 93% decrease in CO_2-eq emissions was also determined for methanol produced from biomass (Wang and Lee, 2017). The WTW CO_2 emissions reduction of methanol from CO_2 capture and recycling was estimated at up to 98% compared to gasoline and diesel. As such, these routes to methanol already fulfil the emission-saving requirements for biofuels in the European Union, which require all biofuels to achieve a GHG emission reduction initially set to at least 35% compared to the emissions of 83.8 g CO_2-eq/MJ from a fossil fuel reference. These emission reduction requirements were gradually increased to 50% in 2017 and 60% in 2018.

Volvo also found that the WTW GHG emissions were reduced by about 90% for methanol and 95% for DME when these fuels were produced from black liquor. Similar results were reported by the European Commission Joint Research Centre, Institute of Energy-EUCAR-CONCAWE collaboration (JEC), which published a series of studies on GHG emissions from a large number of conventional and alternative fuels, production routes and powertrains (Edwards et al., 2011; Edwards et al., 2014). The reports showed that, for example, for a diesel motor[2] the WTW emissions were reduced from 145 g CO_2-eq/km for regular diesel to 5 g CO_2-eq/MJ for DME from black liquor, a reduction of 97% (Edwards et al., 2011).

For DME from waste wood and farmed wood, the reduction was 94% and 92%, respectively. This is well below the 95 g CO_2-eq/km needed to comply with the proposed EU regulation on GHG emissions from new passenger cars for 2020 (EU, 2012a). It is also well below the emissions of DME from coal and natural gas, the latter being on a par with gasoline and diesel emissions on a WTW basis. Methanol was not part of this study, but from a production efficiency point of view, DME (which is dehydrated methanol) and methanol are very close to each other. The energy efficiency for the conversion to methanol is actually slightly higher than that for DME.

As regards energy consumption, the most energy-efficient biomass-to-DME route according to Edwards (2011) is the one based on black liquor gasification. This route has a value slightly below 200 MJ/100 km. Black liquor is the large internal energy stream generated during wood pulp production, which is normally combusted in a so-called recovery boiler to generate power and heat and recover the cooking chemicals. The energy requirement in a mill with DME production is met by the installation of an efficient biomass-fed boiler producing heat and power. This boiler has much higher energy efficiency than the recovery boiler, which is the main reason for the overall high energy efficiency of the concept. Energy efficiency is calculated as DME energy produced divided by added extra biomass energy needed to bring the new mill with DME production to the same overall net energy balance as before adding DME production (Ekbom, 2003). The direct biomass gasification route is around 250 MJ/100 km. This can be compared with cellulosic ethanol, which has energy consumption of around 300-500 MJ/100 km and emits 30-40 g CO_2-eq/km.

Notably, various biogas routes have strongly negative GHG emissions (in this case meaning highly favourable). This is due to the high global warming potential of methane and the fact it would be emitted to the atmosphere if not used as fuel. However, they are large users of energy – more

2 DICI 2010 no DPF: 2010 direct injection compression ignition engine with no diesel particulate filter.

than twice as much as the most efficient biomass to DME/methanol cases described. For heavy-duty buses using DME in compression engines and methanol combined with fuel cells, WTW reductions in GHG emissions of 94% and 96% were calculated, respectively. In this case methanol and DME were obtained from poplar trees (Pont, 2007). In the case of ships, GHG emissions were also considerably reduced when bio-methanol was used instead of heavy fuel oil. Depending on the biomass source and process, reductions of 80% to over 95% were determined (Brynolf et al., 2014; Balcombe et al., 2019). As we move forward, the increased use of biomass and recycled CO_2 with H_2 from renewable energy will make carbon fuels increasingly carbon neutral and renewable. Eventually, CO_2 contained in the atmosphere – either recycled directly or through biomass – will be our predominant source of carbon, solving the problem of excess emissions of this GHG.

Table 11. GHG emissions of methanol from various sources, ordered by feedstock type

Resource type	Feedstock	Original system boundaries	Raw material to final use GHG emitted in g CO_2eq/MJ*	Source
Biomass-based	Farmed wood	(A)	12	Majer and Gröngröft, 2010
	Farmed wood	(A)	16.5	RED II, Annex V, 2018 (EU, 2018)
	Farmed wood (current to near term)	(A)	7.3	Chaplin, 2013
	Farmed wood (novel medium term)	(A)	4.6	Chaplin, 2013
	Waste wood	(A)	10	Majer and Gröngröft, 2010
	Waste wood	(A)	13.5	RED II, Annex V, 2018 (EU, 2018)
	Waste wood	(A)	16.1	Rönsch et al., 2014
	Waste wood	(A)	22.6	BLE, 2017
	Waste wood	(A)	5.3	Chaplin, 2013
	Waste wood	(A)	18.3	Ellis and Svanberg, 2018
	Wood	(D)	25	Kajaste et al., 2018
	Wood chips	(B)	20.91	Ecoinvent, 2019
	Black liquor	(A)	10.4	RED II, Annex V, 2018 (EU, 2018)
	Black liquor	(B)	12	Lundgren et al., 2017
	Black liquor	(A)	3	Chaplin, 2013
	Black liquor	(A)	5.7	Ellis and Svanberg, 2018
	Crude glycerine	(A)	30.6	Chaplin, 2013
	Biogas	(A)	34.4	Chaplin, 2013
	Biogas (manure, crops)	(A)	30	Majer and Gröngröft, 2010

Power-based	Renewable electricity, flue gas from biomass plant	(B)	3.23	Buddenberg et al., 2016
	Renewable electricity, CO_2 from ethanol plant	(A)	13	Matzen and Demirel, 2016
	Renewable electricity, CO_2 from biogas process	(B)	0.5	Hoppe et al., 2018
	Renewable electricity, CO_2 from ethanol plant	(D)	21.3	Kajaste et al., 2018
	Renewable electricity, CO_2 captured from coal power plant	(D)	33.1	Kajaste et al., 2018
	Renewable electricity, flue gas (geothermal energy plant)	(A)	12.1	CRI, 2020
	Renewable electricity, flue gas from biomass plant	(A)	1.74	Chaplin, 2013
Fossil-based	Natural gas	(B)	101.6	Ecoinvent, 2019
	Natural gas	(C)	94	Kajaste et al., 2018
	Natural gas	(A)	91	Ellis and Svanberg, 2018
	Natural gas	(A)	94.4	Chaplin, 2013
	Hard coal	(B)	262	Ecoinvent, 2019
	Hard coal	(C)	219	Kajaste et al., 2018
	Lignite	(A)	170.8	Rönsch et al., 2014

** Raw material to final use GHGs in g CO_2-eq/MJ calculated from the original system boundary:*

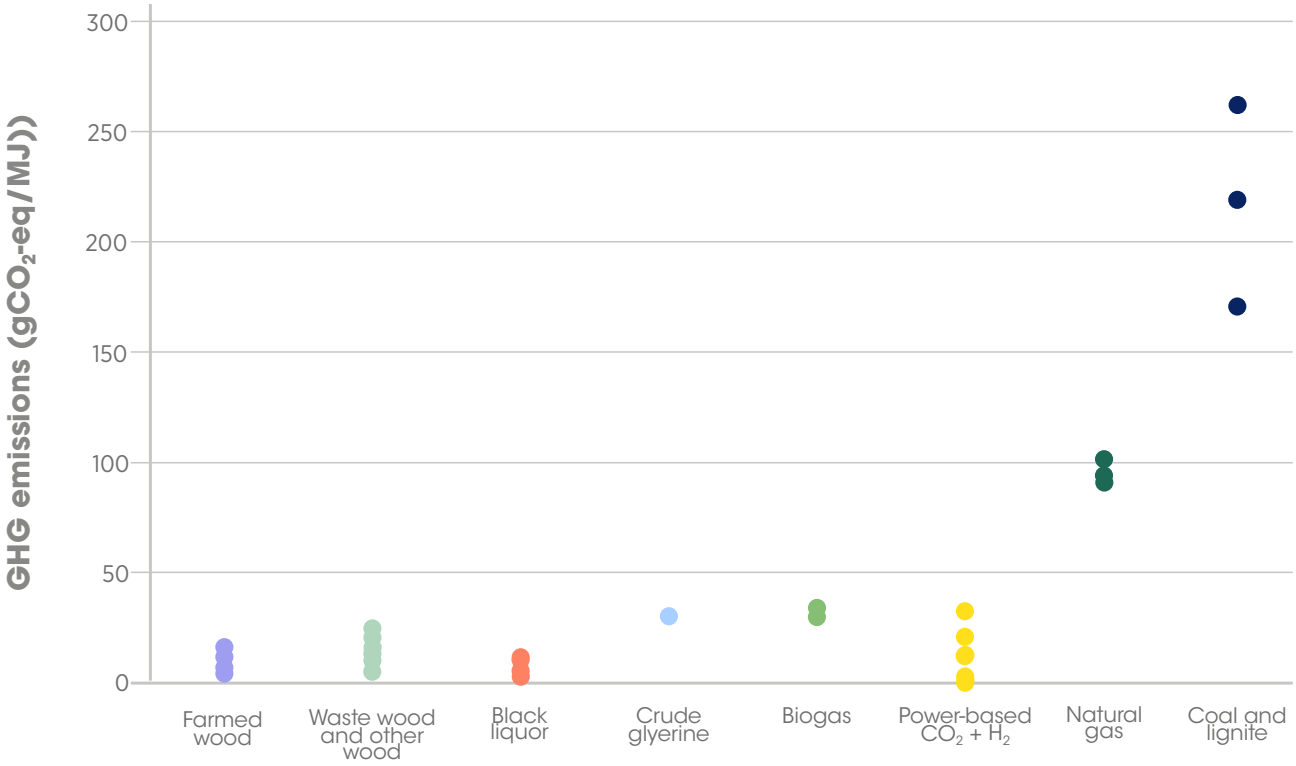
(A) From raw material extraction until use phase; no correction needed.

(B) From raw material extraction until methanol production gate; add the RED II default value of 2.0 g CO_2-eq/MJ for transport and distribution of MeOH.

(C) From raw material extraction until methanol production gate; add the RED II default value of 2.0 g CO_2-eq/MJ for transport and distribution and the combustion emission of MeOH of 69 g CO_2-eq/MJ.

(D) From raw material extraction until methanol production gate; corrected for CO2 emitted during methanol use 69 g CO_2-eq/MJ ; add the RED II default value of 2.0 g CO_2-eq/MJ for transport and distribution of MeOH.

Figure 32. GHG emissions of methanol produced from various feedstocks (from feedstock extraction to final use, values from Table 11)



Sustainability and carbon neutrality

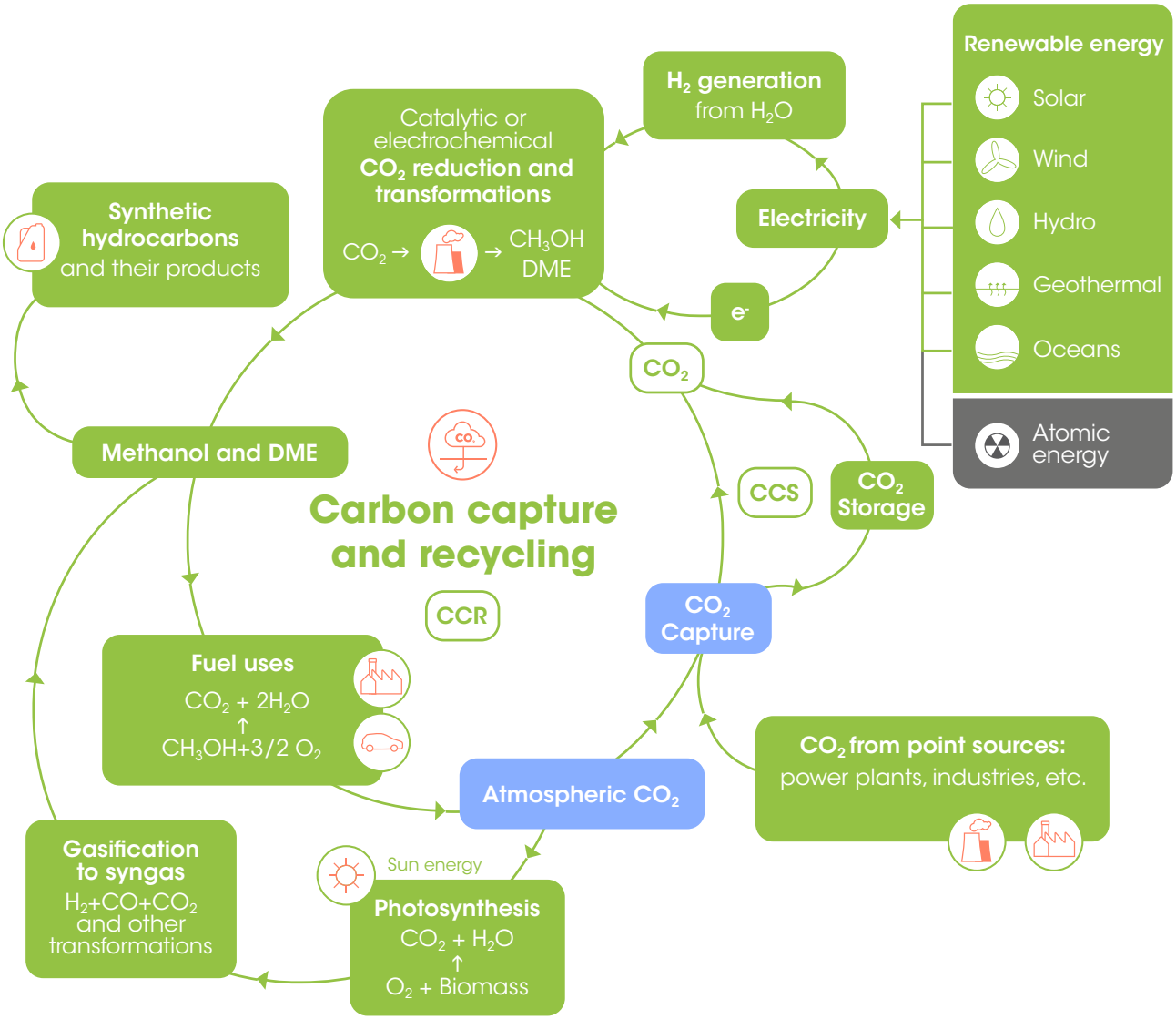
The production of methanol from natural and anthropogenic sources, including biomass and the recycling of CO_2 from flue gases of various industries, could be the first step towards an anthropogenic carbon cycle. The removal of even a fraction of the CO_2 from industrial emissions would result in the availability of huge amounts of CO_2. Using the CO_2 captured from fossil fuel sources one more time to produce methanol instead of simply releasing the CO_2 to the atmosphere could potentially halve the emissions. This type of methanol could be considered a low-carbon fuel.

This approach, however, does not provide a permanent and sustainable solution. As fossil fuels become less abundant and their use regulated by stricter emission standards, related CO_2 emissions will eventually diminish. And even though the carbon in CO_2 is used one more time, it remains fossil carbon. Biomass can help defossilise society. The amounts of biomass that can be generated in a sustainable way are substantial, but nevertheless limited, and are unlikely to be able to cover all our needs (see Chapter 5). A combination of bio- and e- methanol production could allow for full utilisation of renewable carbon in the feedstock, leading to a substantial increase in methanol production from a given amount of biomass. The increase is more than double compared to the conventional approach without the addition of external renewable hydrogen. CO_2 obtained from various other BECCS/BECCU units, especially the ones that burn biomass for electricity generation, could also be used in combination with green hydrogen to generate e-methanol. However, the limitations attached to biomass availability imply that methanol and its derived products should also be increasingly produced from CO_2 captured from the air, which offers an inexhaustible carbon source for humankind. The required energy will have to be provided by renewable energy sources. This would constitute an artificial version of nature's CO_2 recycling via photosynthesis, that is, a sustainable anthropogenic carbon-neutral cycle (Figure 33). This is one of the key concepts of the so-called **methanol economy** (Goeppert et al., 2014; Olah et al., 2018) and also the liquid sunshine concept (Shih et al., 2018).

Methanol from non-renewable sources such as natural gas and coal is already competitive from a cost perspective with gasoline and diesel fuel (Figure 4). It is also an essential feedstock for numerous chemicals, materials and plastics. Hybrid systems using both renewable and fossil fuels with fewer or no CO_2 emissions to produce LCM could be used during the transition period to a sustainable future. LCM could thus be part of a bridge towards renewable methanol.

Once the infrastructure for the distribution and use of methanol and LCM is in place, it could be seamlessly shifted to sustainable renewable methanol in the future. Fossil methanol and renewable methanol are the same from a chemical point of view. Renewable methanol can be a sustainable feedstock for many of the chemicals and products currently obtained from petroleum, including aromatic compounds (BTX) and plastics (polyethylene, polypropylene) (Bazzanella and Ausfelder, 2017).

Figure 33. Anthropogenic carbon cycle for a circular economy



Source: *Olah et al. (2018).*

4. CURRENT COSTS AND COST PROJECTIONS

The cost of bio- and e-methanol produced from renewable sources depends on a variety of factors, including feedstock, choice of technology, energy demand, production capacity, operating conditions, desired purity of the product and availability of tax incentives.

4.1. Bio-methanol costs

Methanol production from biomass and MSW via gasification

For bio-methanol the methodology applied in this report to determine the cost of production is similar to that used and accepted by a large number of stakeholders. This was confirmed during the process of assembling and arranging information used as the basis for the "Cost of Biofuels" report by the Sub Group on Advanced Biofuels (SGAB) (Maniatis et al., 2018), a group under the Sustainable Transport Forum (EU STF, 2019).[3]

The cited report was used as a basis for a project presented in a report named "Advanced Biofuels – Potential for Cost Reduction" (Brown et al., 2020). The information on projects utilising thermal conversion of biomass in these two reports was updated and adjusted for this report and the same approach to estimate production costs for various biofuels applied.

The method identifies the CAPEX contribution, the OPEX contribution (excluding feedstock) and the feedstock contribution. The CAPEX was calculated using data from projects that were under construction where such data were available. Costs were sometimes based on the cost estimates for projects similar to that being investigated.

In this report, the investment intensity is presented as USD/t/y as one product is in focus. In some cases where methanol is not the product, USD/kW of product has been added in order to be able to compare against a common base – energy. When comparing investment intensity, the size of various plants is an important consideration. CAPEX is seen as equal to the overnight investment cost for building the plant and no costs for interest during construction or working capital are added. The capital recovery charge is composed of an annual cost estimated as a levelised annual capital cost (based on an annuity loan using a real interest rate of 10% for 15 years, i.e. a factor of 13.2%, expressed as CAPEX per year or CAPEX/y). Elements of a fully elaborated project economic model, such as level of grant support, debt-to-equity ratio, loan repayment grace period and amortisation periods, are not included.

OPEX, less feedstock, is expressed as an annual percentage of CAPEX or as a percentage of the production cost. The percentage includes co-feeds, labour, feedstock-associated costs on the site, maintenance and by-product disposal. When available, relevant data from project estimates were the basis for the percentage or other figures used.

The feedstock cost contribution is estimated from the performance data and feedstock cost.

The production cost is estimated as the sum of the capital recovery charge, OPEX and feedstock procurement costs on an annual basis divided by the production output.

During Q2-3 of 2020 a number of project developers and plant owners were contacted for information, as specified in Table 4. Table 12 and Table 13 present relevant information received, from which the CAPEX element in the production cost can be specified. Table 12 lists projects that have specified methanol as an end product, and Table 13 other gasification-based projects.

3 The STF was formed in 2015 as a vehicle to implement the so-called Alternative Fuel Infrastructure Directive 2014/94/EU (EU, 2014). The forum has members from all EU member states plus about 40 specialists and is headed by DG MOVE.

Table 12. Capital cost for bio-methanol plants

#	Project/ study	Status	Capacity (t/y)	Investment (million USD)	Investment (USD/t/y)	Investment (USD/kW)	Source
1	Trans World Energy (TWE), Florida (US)	FEED done, start-up Q2 2023	875 000	430	490	710	TWE
2	ENI Refinery, Livorno (IT)	Basic engineering ready Q3 2020	115 000	330	2900	4 280	NextChem
3	LowLand Methanol (NL)	Start-up early 2023	120 000	130	1 110	1 620	LowLand Methanol
4	Södra (SE)	Operational	5 000	11	2 220	3 230	Södra
5	Enerkem, Rotterdam (NL)	Engineering	215 000	580	2 690	3 840	Enerkem
6	Enerkem, Tarragona (ES)	Engineering	215 000	580	2 690	3 840	Enerkem
7	VTT	Detailed study	265 000	385	1 450	2 070	VTT
8	Chemrec, Domsjö (SE)	Preliminary engineering	147 000	390	2 640	3 400	Chemrec
9	Chemrec, nth plant	Concept	290 000	540/270*	1 880/930*	2 740/1 370*	Chemrec
10	New Hope Energy, Texas (US)	Investment decision Q4 2020	715 000	500	700	1 020	New Hope Energy

** This investment is credited for the avoided investment in a new recovery boiler.*

Projects listed in Table 13 do not produce methanol. The feedstocks and production pathway via syngas and then a synthesis plant to a product are, however, similar to a plant configuration producing methanol. Syngas generation, conditioning and cleaning comprise the major part of the overall investment regardless of the final product. Therefore, if investment per unit of production capacity (USD/kW) is compared between the two tables, a relevant comparison can be made. There is, however, a need to include the potential effect of larger or smaller investment in the synthesis unit (e.g. methanol versus FT products), as well as the overall conversion efficiency from feedstock to product. This is further discussed below.

Table 13. Capital cost for gasification-based plants for other products

	Project/product	Status	Capacity per year	Investment (million USD)	Investment (USD/kW)	Source
1	Enerkem, Edmonton (CA)/ethanol	Operational	30 000 t	87	3 110	Enerkem
2	Enerkem, Quebec (CA)/ethanol	Announced/ construction	35 000 t	78	2 800	Public domain
3	Fulcrum (US)/FT liquids (jet fuels)	Start-up Q4 2020	40 000 m^3	200	4 560	Public domain
4	Red Rock Biofuels/ FT liquids (jet fuels)	Under construction, start-up 2021	58 000 m^3	355	5 560	Public domain
5	E.On/SNG	Planned	1 600 GW	470	2 280	E.On

Note: *SNG = synthetic natural gas.*

Capital cost element of total production cost

CAPEX was converted into an investment intensity, expressed as an average value with an interval of +/- 20% and was expressed as USD/kW of product capacity to allow comparison of CAPEX for various projects with different products. The capital cost range was then compared and adjusted in a conservative way with other studies such as Brown et al. (2020) and Maniatis et al. (2018). The range of investment cost for a biomass-fed plant is assumed to be 1 560-2 220 USD/t/y and for MSW-based projects to be 2 000-2 780 USD/t/y. The relative investment for MSW-based projects was higher, but these plants are normally at a smaller scale, in the range of 100 000 t/y of methanol compared to 200 000-250 000 t/y for biomass-based projects, explaining why a higher relative investment should be expected.

The new and updated data presented in Table 12 and Table 13 was obtained from various information providers. There are, however, exceptions such as the large Trans World Energy and New Hope Energy projects in Table 12. These should clearly have relative investment at the lower end of the proposed interval due to the effect of economies of scale, but the investment numbers provided are even below that. Low relative investment can also be observed for the LowLand Methanol project in the same table. This has partly to do with the fact that a large proportion of the methanol production comes from imported hydrogen (the investment-intensive gasification part of the project is thus correspondingly smaller). It also has a number of advantages in the form of easily accessible utilities.

As explained between the two tables, projects can be compared on a "cost per kW of product capacity" basis, but taking into account various specific circumstances for each referenced project.

Comparing the projects in Table 12 and Table 13 on such a USD/kW basis (noting that tonnes of aviation fuel cannot be compared with tonnes of methanol) shows that:

- The Enerkem Edmonton plant (Table 13), which produces methanol from MSW for further conversion

to ethanol, has a relatively low relative investment in USD/kW of ethanol despite being of small size. If feedstock preparation were included, this investment level would increase to about USD 4 220/kW.

- For the E.On. project (Table 13) bioSNG production corresponds to about 250 000 t/y of methanol production and falls in the middle of the interval presented for this size of methanol plant.

- The Fulcrum and Red Rock Biofuels projects (Table 13), both aiming to produce FT products, are comparably small plants with a production capacity corresponding to less than 100 000 t/y of methanol equivalents. They also have a lower conversion efficiency, which affects the relative investment negatively, as do the additional upgrading units needed in order to produce saleable products for the market. Their data points at USD 4 440-5 560/kW are therefore not surprisingly high.

- In the first referenced Chemrec project (Table 12) the investment does not include a credit for avoiding the investment in a replacement for the current recovery boiler. It carries the cost of the boiler replacement. This was agreed because that project would be the first of its kind and the pulp mill thus acts as a test mill for a new technology.

- The second referenced Chemrec black liquor project (Table 12) will in its commercial application (n^{th} plant case) be credited for avoiding the investment in a replacement for the current recovery boiler. This implies that the net investment has decreased by approximately half.

- With a specific investment for plants utilising biomass feedstock of 1 560-2 220 USD/t/y and based on a capital cost per year corresponding to 15 years and 10% (annuity percentage of 13.2%), the result is a cost of capital element in the product cost of USD 206-293/t or USD 37-53/MWh of methanol (Table 14).

- For MSW-based projects with investment in the range of 2 000-2 780 USD/t/y, the cost of capital in the product cost is USD 264-367/t or USD 48-66/MWh.

Feedstock cost element of total production cost

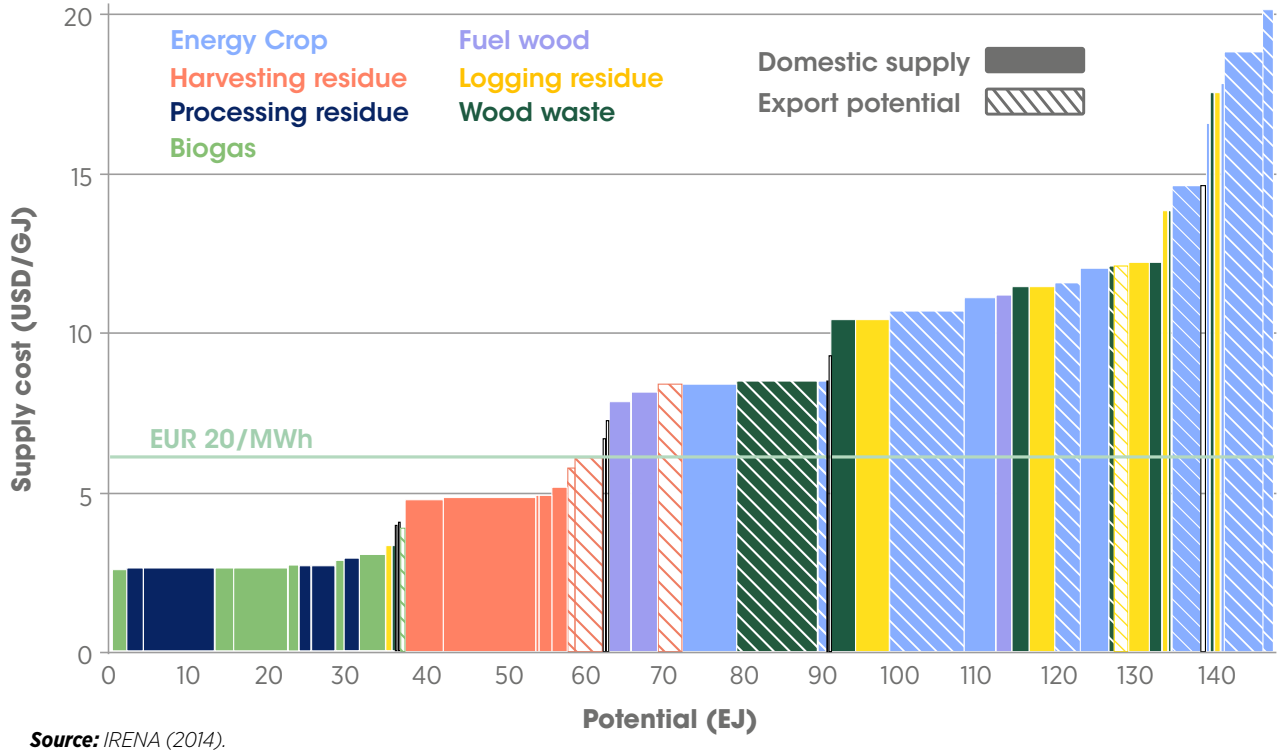
The energy conversion efficiency for biomass to methanol is in the order of 60% (based on the feedstock LHV at the plant gate). In the special case where black liquor in a pulp mill is gasified and converted to methanol and the black liquor energy is compensated by biomass fed to a utility boiler on the site, the overall efficiency may reach around 70% (ratio of added biomass to produced methanol). For MSW projects the conversion efficiency is generally somewhat lower, around 50-60%.

Cost of feedstock varies considerably depending on the location of the facility and type of feedstock. Figure 34 shows a global supply curve for primary biomass (IRENA, 2014). Domestic biomass feedstock cost ranges from approximately USD 3/GJ for processing residues in Africa to USD 17/GJ for energy crops. The lowest feedstock cost of below USD 5/GJ can be found with MSW and processing residues. The medium cost group between USD 5 and USD 8/GJ consists of harvesting residues. And higher costs are mostly found in energy crops and forestry products.

Table 14. Capital cost element in production cost

CAPEX/y	From biomass		From MSW	
	Low	High	Low	High
USD/t MeOH	206	293	264	367
USD/MWh MeOH	37	53	48	66
USD/GJ MeOH	10.4	14.7	13.3	18.4

Figure 34. Global supply curve for primary biomass, 2030



Source: *IRENA (2014).*

In Europe and the United States a typical price of woody biomass at the plant gate is EUR 50-100 per dry tonne (USD 3-6/GJ) according to Brown et al. (2020). In the southern United States, parts of Canada and in Brazil the price can be even lower, in the order of EUR 25-50 per dry tonne (USD 1.5-3/GJ).

The price of EUR 20/MWh (USD 6/GJ) is indicated in Figure 34 to illustrate the above-referenced price levels. It is also used as a threshold when describing the total production cost of bio-methanol, illustrating the feedstock part of the total production cost. About 40% of the feedstock potential would be available below this price level.

Table 15 shows the cost of the feedstock element in the total production cost as a function of the energy conversion efficiency. In some cases, the feedstock may even come with a credit at that point. This potential credit is not included in the production cost estimates.

Table 15. Feedstock cost element in production cost

Feedstock cost USD/GJ feedstock	Conversion efficiency, feedstock to methanol, %					
	50		60		70	
	USD/GJ MeOH	USD/t MeOH	USD/GJ MeOH	USD/t MeOH	USD/GJ MeOH	USD/t MeOH
15	30.0	597	25.0	498	21.4	426
10	20.0	398	16.7	332	14.3	284
6	12.0	239	10.0	199	8.6	171
3	6.0	119	5.0	100	4.3	85
1.5	3.0	60	2.5	50	2.1	43

OPEX (excluding feedstock) element of total production cost

Operating costs other than feedstock (such as utilities, catalysts, chemicals, operations and maintenance) are often not specified for projects at various stages of planning, and when plants are operational OPEX information is not provided for commercial reasons. Available information is often aggregated and expressed as an annual percentage of total investment cost (CAPEX). Based on various sources contacted during the course of developing this report, low numbers are in the 5-6% range and high are about twice as much, 9-10%. For waste gasification, the specific investment cost is higher, and therefore the lower percentage still seems reasonable as the operating cost contribution, expressed per tonne per year, is higher than that for biomass feedstock. This reflects, for example, the added cost for treatment of higher levels of contaminants in the feedstock, together with disposal of ash and other secondary wastes. The variation in OPEX costs are summarised in Table 16.

Total methanol production cost from biomass and MSW

Adding the three cost elements from Table 14, Table 15 and Table 16 together provides the total production cost for methanol from biomass and MSW for various cases, including low and high costs for investment, feedstock and OPEX. These are put together in Table 17. As can be expected the interval between the most cost-effective cases and the most expensive is quite large. Low production cost cases are around USD 300/t, increasing to about USD 600/t for high CAPEX, high OPEX and feedstock at USD 6/GJ. It increases further to about USD 1 000/t at a feedstock cost of USD 15/GJ combined with high CAPEX and OPEX.

Potential production cost reduction for methanol from biomass and MSW

With respect to the potential for cost reduction, the CAPEX part of the equation, first and foremost, can be influenced to a noticeable degree. Low-priced feedstock is already part of the cost interval above and it is not likely that other OPEX costs can decrease much below the 5% of CAPEX per year, which is the low number used in the calculations.

The interval given for overall energy efficiency also includes future developments and the cost of the feedstock element in the total production cost would therefore not be expected to decrease due to this.

CAPEX can, however, expect to be influenced over time by the well-known learning curve mechanisms such as process improvements, improved and more (cost-) effective plant configurations and plant size (economies of scale). In the Brown et al. (2020) report regarding potential cost reductions, this long-term potential is quantified as 20-30%.

The capital burden in the production cost is based on an internal rate of return (IRR) of 13.2%, corresponding to 15 years and 10% annuity financing of the total capital. In the long term, when the technology is well-known and risks have been mitigated through extensive learning experiences, the cost of capital may come down.

Table 16. OPEX (excluding feedstock) cost element in production cost

			Biomass as feedstock		MSW as feedstock	
			Low	High	Low	High
	CAPEX, USD/t MeOH/y		1 560	2 220	2 000	2 780
OPEX Low	5%	USD/t MeOH	78	111	100	139
OPEX High	10%	USD/t MeOH	156	222	200	278

Table 17. Total production cost for bio-methanol from biomass and MSW

		Biomass as feedstock				MSW as feedstock			
		Low		High		Low		High	
CAPEX/y, USD/t MeOH		206		293		264		367	
Overall conversion efficiency, %		60	70	60	70	50	60	50	60
Feedstock cost element for methanol at various level, USD/t MeOH	At USD 15/GJ	498	426	498	426	-	-	-	-
	At USD 10/GJ	332	284	332	284	-	-	-	-
	At USD 6/GJ	199	171	199	171	-	-	-	-
	At USD 3/GJ	100	85	100	85	119	100	119	100
	At USD 1.5/GJ	50	43	50	43	60	50	60	50
	At USD 0/GJ [a]	-	-	-	-	0	0	0	0
OPEX at 5%, USD/t MeOH		78		111		100		139	
OPEX at 10%, USD/t MeOH		156		222		200		278	
Cost of methanol (USD/t MeOH)	Feedstock cost below USD 6/GJ	327-561		447-714		414-583		556-764	
	Feedstock cost at USD 6-15/GJ	455-860		575-1 013		-		-	
Carbon credit (USD/t MeOH)	At USD 50/t CO_2 [b]	-82		-82		-82		-82	
	At USD 100/t CO_2 [b]	-164		-164		-164		-164	

(a) USD 0/GJ for the feedstock being fed to the MSW gasifier is indicative and not used in the cost estimates.

(b) The carbon credit per tonne of bio-methanol is based on the difference between the average CO_2-eq emissions from methanol production from natural gas (95.2 g CO_2-eq/MJ) and the average CO_2-eq emissions from bio-methanol production from renewable CO_2 and H_2 (12.7 g CO_2-eq/MJ) given in Table 11. Considering an LHV of 19.9 MJ/kg for methanol, this corresponds to 1.64 t CO_2-eq of emissions avoided per tonne of bio-methanol, compared to the traditional natural-gas based methanol.

If the capital part of the production cost were based on an IRR of 10.2%, corresponding to 20 years and 8% annuity financing, the cost of capital would be 23% lower than presented in Table 14.

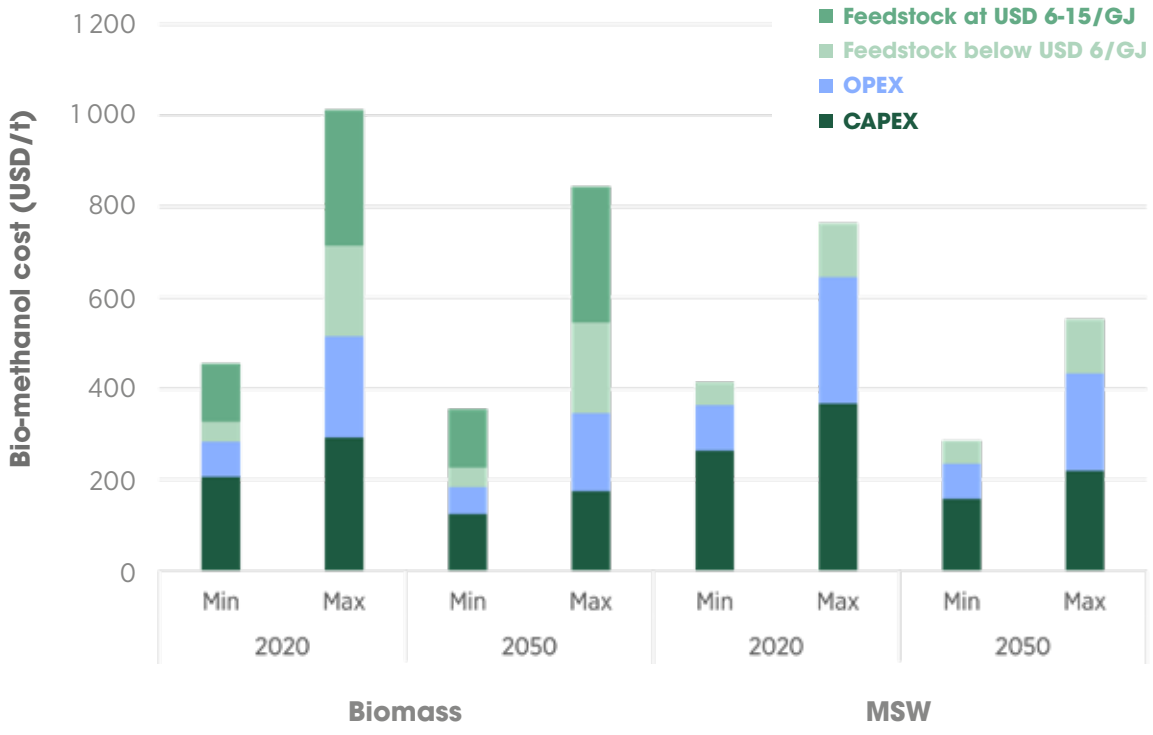
The potential for learning curve and capital risk mitigation cost reductions, if combined, lowers the capital cost element (CAPEX/y) of the total production cost by 40-45% (40% is used in the table below), distributed approximately evenly between the two identified cost reduction elements. OPEX is related to investment and is assumed to be reduced proportionally with the cost of capital. The results of the cost reduction assumptions are shown in Table 18 and in Figure 35.

Table 18. Total production cost for bio-methanol after potential cost reduction

		Biomass as feedstock		MSW as feedstock	
		Low	High	Low	High
Before cost reduction USD/t MeOH (from Table 17)	Feedstock below USD 6/GJ	327-561	447-714	414-583	556-764
	Feedstock at USD 6-15/GJ	455-860	575-1 013	-	-
CAPEX/y reduction, USD/t MeOH		-82	-118	-106	-147
OPEX reduction, USD/t MeOH		-18 to -36	-26 to -51	-23 to -46	-32 to -64
Cost of methanol (USD/t MeOH) at feedstock cost below USD 6/GJ	With no carbon credit	227-443	303-545	285-431	377-553
	With a credit of USD 50/t CO_2 *	145-361	221-463	203-349	295-471
	With a credit of USD 100/t CO_2 *	63-279	139-381	121-267	213-389
Cost of methanol (USD/t MeOH) at feedstock cost at USD 6-15/GJ	With no carbon credit	355-742	431-844	-	-
	With a credit of USD 50/t CO_2 *	273-660	349-762	-	-
	With a credit of USD 100/t CO_2 *	191-578	267-680	-	-

** Please see the note in Table 17.*

Figure 35. Estimated costs of bio-methanol up to 2050



Cost reduction activities are closely related to operating experiences and how gained knowledge is preserved and used over time when new facilities are brought online using the same (improved) process. It typically takes at least four years from a preliminary project idea until a plant is up and running. Thereafter at least a year of operation is necessary before any real conclusions can be made from gained experiences. Therefore, a scenario describing the potential production cost savings, as per above, against time is very much dependent on the number of plants built over time. The word "plant" used in this cost reduction section should rather be understood as "plant generation". After changes from one generation to the next, decisions could be taken to build multiple units to meet market demand and ensure economic production.

Figure 36 illustrates a production cost reduction scenario where 4 plant generations producing bio-methanol are put into operation over about 15 years (2020-2035). The upper limit for the cost of feedstock in this illustration is USD 6/GJ. Four or five different development pathways are expected to be commercialised and reach maturity in parallel efforts. Following this development, the potential cost reduction according to data presented in Table 18 is expected to be achieved.

Analogous with bio-methanol, Figure 37 presents the corresponding cost reduction potential for MSW-based plant generations and plant installations

The scenarios presented should be regarded as fast tracks. They are built on the assumption that plants now at an advanced stage of planning and under construction (in one case operational) are the first generation of plants, which will be followed by three plant generations of similar but improved design in the coming period up till 2035-2040. In another, slower scenario where long-term stable legislation for the introduction of advanced fuels and chemicals does not materialise, the timeline can easily become much longer.

Methanol production from biogas

Biogas is mostly used for power and heat generation. Small quantities are upgraded to gas pipeline quality (biomethane) and blended into the natural gas network or mixed with natural gas in order to create an automotive fuel with a low-blend renewable component. In some countries, which for example do not have a gas network, smaller volumes are handled separately in tankers and used as 100% renewable automotive fuel.

Figure 36. Potential production cost reduction for bio-methanol from biomass within a 15 to 20 year timeframe

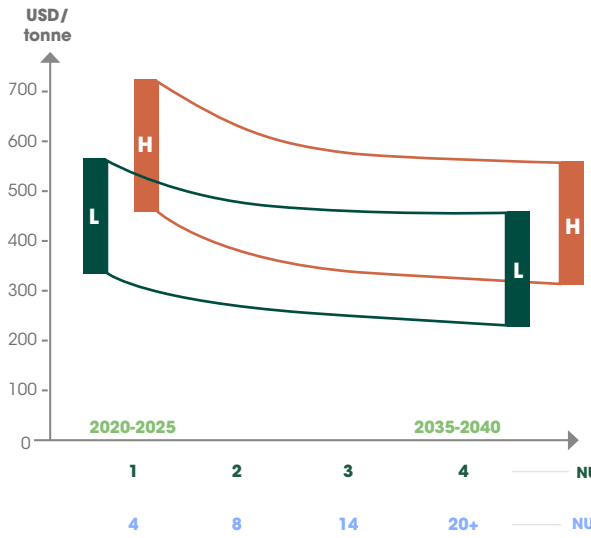


Figure 37. Potential production cost reduction for bio-methanol from MSW within a 15 to 20 year timeframe

At two locations in Europe biomethane is co-fed with natural gas into existing methanol plants. In this way, the product is a mix of fossil and bioderived methanol. The renewable part is formally certified and can be traded as a renewable commodity. For more details see Section 2.2.

A process plant converting methane to methanol will function identically regardless of whether the methane is of fossil or renewable origin. This means that if an existing methanol plant replaces part of its methane feedstock from fossil to renewable origin, only the difference in feedstock price will affect the final production cost of methanol.

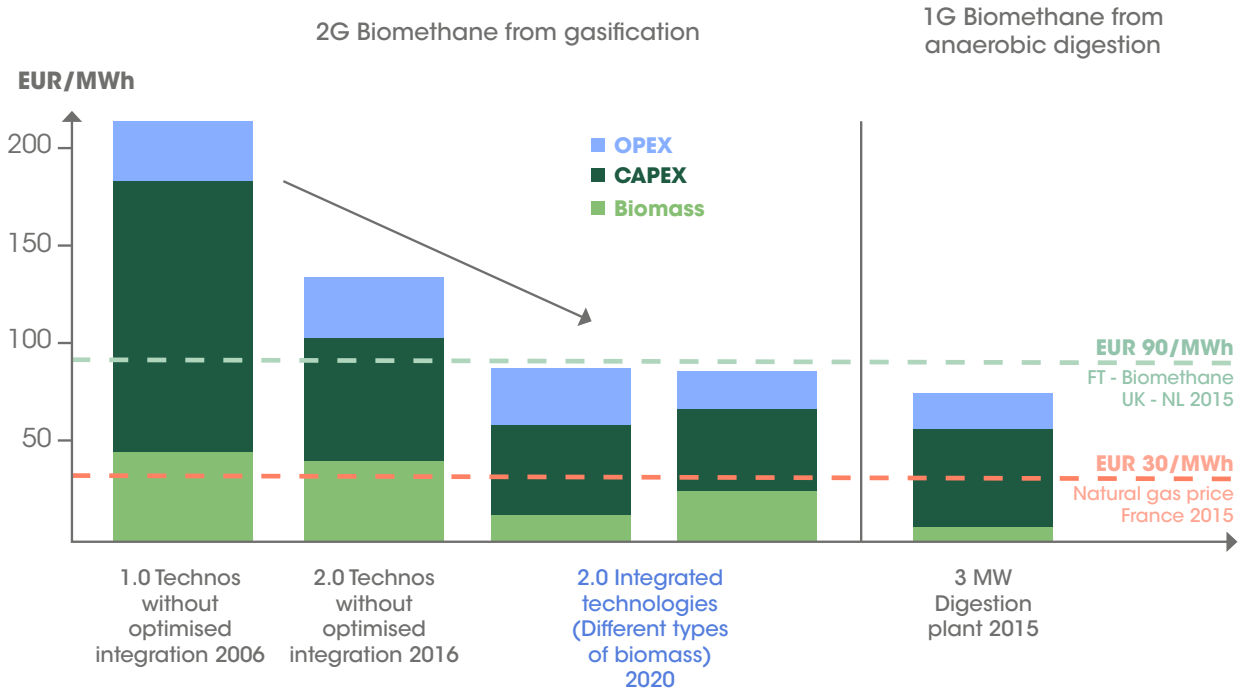
In 2019 non-household natural gas in Europe had an average price of about EUR 35/MWh (USD 10.8/GJ) (Eurostat, 2020). According to data provided to the SGAB report (Maniatis et al., 2018), typical biomethane production costs are in the range of EUR 70-80/MWh (USD 21.6-24.7/GJ) when based on anaerobic digestion. Large and modern gasification-based plants are expected to reach similar production cost levels as shown in Figure 38.

The feedstock price effect on overall production is shown in Table 8. The impact on methanol production costs when moving from natural gas to biomethane feedstock is clearly substantial. In the example shown in the table, it corresponds to an increase of USD 377/t of methanol. Corresponding calculations for the United States would show an even larger difference because natural gas prices there are generally lower than in Europe.

Production economics for a new installation are not covered in this report. To install a small to medium-sized plant in, for example, Europe, which would only be fed with biomethane, would lead to a very high production cost. The feedstock cost alone would be in the order of USD 700/t of bio-methanol, to which CAPEX and OPEX need to be added.

An alternative to the above route via biomethane which is currently being investigated by, for example, Haldor Topsoe in Denmark is direct conversion of biogas in an electrically heated biogas reformer to generate syngas for further conversion to methanol. They call their development eSMR Methanol™ (HT, 2019b).

Figure 38. Production cost for biomethane via gasification and via anaerobic digestion



Source: *EBA (2020).*

Table 19: Impact of feedstock price in production of methanol from methane/biomethane

	Biomethane price	Feedstock cost in production cost of methanol (conversion efficiency 65%)		Impact on production cost
	USD/GJ biomethane	USD/GJ MeOH	USD/t MeOH	USD/t MeOH
Natural gas in western Europe	10.8	16.6	329	+ 377
Biomethane	23.1	35.5	706	

A 10 kg per hour methanol demonstration plant is planned to be operational in 2022. Haldor Topsoe claims that its compact and modular design should result in plants that can be built on a commercially attractive basis at a scale 100 times smaller than today's typical plant sizes, and produce methanol at the same production cost level as large fossil gas-fed plants.

Methanol as by-product from wood pulping

Methanol extraction from pulp mills is a niche pathway with limited global capacity. Worldwide capacity is estimated to be less than 1.5 Mt in more than 300 pulp mills.

As described in Section 2.2, there are very few references for this conversion pathway. Only two have been identified, one in Sweden and one in Canada. Methanol is currently used in pulp mills as a green fuel, for example in the lime kiln or in an on-site utility boiler. This means that if such methanol had to be withdrawn from the mill and sold as chemical-grade methanol it would have to be substituted by another fuel. In most cases this fuel would be an inexpensive biomass, but in other locations a more costly lime kiln fuel could be needed.

Södra has provided some official data (Södra, 2020b). The investment is estimated at about EUR 10 million (USD 11 million) and capacity is calculated to be 5 250 t/y of chemical-grade bio-methanol. If the same CAPEX factor (IRR=13.3%) is used for this investment as earlier in this chapter, the CAPEX element in the production cost corresponds to EUR 250/t (USD 280/t). One tonne of methanol provides about 5.5 MWh of combustion energy and if this is substituted with biomass at EUR 10-20/MWh (USD 3-6/GJ) it would add another EUR 55-110/t (USD 60-120/t) to the OPEX. The process of making pure methanol has a number of extraction and distillation steps, which will lead to additional OPEX-related costs. An approximate estimate for bio-methanol production from the pulping cycle is shown in Table 20. It gives a production cost of about EUR 490-720/t (USD 540-800/t).

Table 20. Approximate production cost for bio-methanol from wood pulping

Cost element	USD/t MeOH
CAPEX	280
Feedstock replacement	60-120
OPEX	200-400
Total	540-800

4.2. E-methanol costs

In the short term, the production of methanol from biomass and waste products seems to be the most economic route in most locations. However, the available amounts of biomass and derived materials, despite being enormous, are also limited and will not be able to cover global energy needs by themselves. The largest potential for the production of renewable methanol remains with the hydrogenation of CO_2 to methanol. Production from CO_2 does not suffer the same feedstock availability limitations as biomass or waste products.

To produce e-methanol sustainably from the CO_2 in the waste gas stream and flue gases of industry and electricity generation, or from atmospheric CO_2, the most mature and scalable method is the combination of water electrolysis to produce H_2 and subsequent catalytic methanol synthesis with CO_2. The cost of e-methanol produced by this route is highly dependent on the cost of the raw materials: CO_2 and hydrogen. The cost of hydrogen itself is closely linked to the cost of the electrical power needed to produce it. To produce one tonne of e-methanol, about 10-11 MWh of electricity are needed, most of it for the electrolyser (~9-10 MWh), and not including CO_2 capture.

As in the case of natural gas plants, some economies of scale should be achievable, resulting in a lower cost per tonne of methanol produced at larger plants. In principle, there is no reason why renewable methanol plants should not be the same size as conventional plants, as the technology is the same regardless of the raw material source. As with other large thermocatalytic processes akin to fossil fuel methanol facilities, the methanol synthesis unit and distillation unit can exploit the lower production costs associated with economies of scale. The electrochemical process of water electrolysis can also benefit from cost reductions with increased module size, and innovation to increase stack manufacturing may have significant impacts on cost.

As a comparison, methanol from natural gas has a production cost of between about USD 100/t where natural gas is the cheapest (Middle East, North America) and USD 300/t or more in Europe. The production cost of methanol from coal, almost exclusively located in China, is roughly between USD 150 and USD 250/t (McCaskill, 2019; Blug et al., 2014).

E-methanol production costs – A literature review

A number of studies have been conducted on the cost of producing methanol from CO_2 and H_2. In 2007 a review evaluated the cost of production for CO_2-based methanol as being between USD 550 and UDS 670/t (EUR 500-600/t) (Galindo Cifre and Badr, 2007). In the previous version of this IRENA report, the production cost using CO_2 captured either from flue gases or the atmosphere was estimated at USD 570-1 000/t (EUR 510-900/t) (Clausen et al., 2010; Galindo Cifre and Badr, 2007; Kim et al., 2011; Specht et al., 1998; IRENA and IEA-ETSAP, 2013). Similar estimates were also obtained in a more recent paper that reviewed past studies, as well as other publications on the subject (Hank et al., 2018).

An overview of these estimated production costs is presented in Table 21. Overall the costs are roughly between USD 300 and USD 1 000/t of e-methanol, with plant sizes ranging from 4 000 t/y to 1.8 million t/y capacity. The lower estimates tend to have very low electricity production costs or/and cross-subsidise the price of methanol from the sale of oxygen co-produced during the electrolysis (from USD 45 to USD 180/t of O_2 sold). For each tonne of methanol produced, 1.5 t of oxygen are generated from the electrolysis of water. The sale of this oxygen could thus offset some of the costs of e-methanol production in the short term. However, as availability of large amounts of oxygen from the electrolysis increases as a by-product of e-fuels production, the supply will probably outpace demand, leading to lower prices. If the sale of oxygen is not taken into account, the overall cost of producing e-methanol is in a range of approximatively USD 400 and USD 1 000/t, depending mostly on the cost of electricity. The cost of CO_2 in most studies is between USD 0 and USD 55/t. In the case of DAC, the cost to capture CO_2 would be higher (Bos et al., 2020; Specht et al., 1998; Specht and Bandi, 1999).

Table 21. Production costs and production capacity of e-methanol reported in the literature

Carbon source	Electricity source for electrolysis	Cost of electricity (US¢/kWh)	Cost of CO_2 (USD/t)	capacity (t/y)	Capital cost (USD million)	Capital cost (USD/t/y)	OPEX (USD million/y)	OPEX (USD/t)	Methanol cost (USD/t)	Source
Biogas/ ammonia	Grid/ wind	3.5-16.2	0-3.3	4 000-10 000	16-30	1 680-4 700	2.6-12.3	510-1 270	680-1 610	Hank et al., 2018
DAC	Wind	---	---	65 000	222	3 330	---	---	830-890 (a)	Bos et al., 2020
Purchased	Grid	2.4-7.3	59	100 000	134	1 340	---	---	365-826 (b)	Zhang et al., 2019
Flue gas	Hydro power	---	---	100 000	333-555	3 330-3 890	---	---	890-1 000 ~555 (g)	Swiss Liquid Future, 2020b
Flue gas/ DAC	Hydro power	2	---	70 000	---	---	---	---	390-590	Specht and Bandi, 1999
CPP flue gas/DAC	Hydro power	3.9	---	70 000	---	---	---	---	805-1 090	Specht et al., 1998
CPP flue gas	RES	1.7-2.4	---	60 000-120 000	95-322	1 640-3 010	16.8-36.9	230-300	620-950	Mignard et al., 2003
CPP flue gas	Grid/RES	4.4	15	300 000	344	1 150	161	540	620-710 (h)	Clausen et al., 2010
CPP flue gas	Grid/CPP	3.2-5.5	49	110 000	---	---	---	---	970-1 010	Atsonios et al., 2016
Ethanol plant	Wind	---	---	32 000	30	944	---	---	405-1 070	Matzen et al., 2015
CPP flue gas	CPP	10.5-13.4	0	440 000	552 (i)	1 260	325	740	805 (f)	Pérez-Fortes et al., 2016
Purchased	RES	10.3	56	35 000	51 (i)	1 480	---	---	1 090 (f)	Tremel, 2015)
CPP flue gas	RES	2.9-3.7	22	30 000-45 000	56	1 240-1 900	---	---	500-530	Varone and Ferrari, 2015
---	---	5.5	3.3-11	16 300	16	980	13.7	840	990	Rivera-Tinoco et al., 2016

Flue gas	RES	1.1-5.5	44	1 800 000	2 310	1 385-2 770	---	---	430-910	Räuchle et al., 2016
Flue gas	---	1.1-6	---	50 000	95	1 900	11-38.3	220-770	210-720 (c) 455-970 (b)	Bellotti et al., 2019
---	Wind	---	(-22)-39	175 000	370	2 110	---	---	390-480 (d)	González-Aparicio et al., 2017
Flue gas	Grid	---	---	4 000-50 000	11-83	1 670-2 780	---	---	555-780 (d)	Bellotti et al., 2017
Flue gas	---	---	28	1 800 000	424 (i)	235	755-1 670 (e)	420-922	420-940 (e, f)	Nyári et al., 2020
Flue gas	RES	3	(-278)-0	100 000	62	620	79	880	810-1 190 (j)	Szima and Cormos, 2018
CPP flue gas	Grid/RES	4.4	43	110 000	---	---	---	---	645	Kourk-oumpas et al., 2016

(a) Includes capital cost for a 100 MW wind farm.

(b) Without sale of oxygen.

(c) With sale of oxygen.

(d) Costs with and without sale of oxygen.

(e) Cost depends on price of hydrogen purchased and with or without oxygen sale.

(f) Hydrogen purchased.

(g) Estimated cost for methanol produced in the wind and solar belts of the world.

(h) With and without district heating income.

(i) Cost of methanol plant does not include hydrogen production.

(j) With and without a negative value of USD 278/t for CO_2.

Notes: *Methanol cost in 2018-2019 USD/t. Exchange rate of USD 1 = EUR 0.9. CPP = coal power plant. RES = renewable energy source. US¢ = US cents.*

E-methanol production costs based on feedstock costs

The cost of e-methanol can also be estimated from the cost of hydrogen and CO_2, which in large e-methanol plants will represent most of the production cost. Once CO_2 and green hydrogen are provided, the production of methanol in a single step and its distillation are quite straightforward and a mature technology (TRL 8-9).

It will only represent about USD 30 to USD 50/t of the total cost of methanol production (Boulamanti and Moya, 2017). To produce 1 t of methanol, 0.188 t of H_2 and 1.373 t of CO_2 are needed.

Cost of hydrogen: Electrolysis of water is an energy-intensive process. Producing 1 t of hydrogen with a 100% theoretical efficiency requires 39.4 MWh of electricity (HHV of H_2; 33.3 MWh/t for the LHV of H_2). In practice, however, it is closer to 50 MWh/t (Simbeck and Chang, 2002; IRENA, 2018). The cost of hydrogen is thus closely linked to the cost of the electricity needed to produce it. Renewable electricity prices continue to decrease. In many places around the world, electricity from solar PV and onshore wind is now cheaper than from fossil fuel sources and expected to continue falling to reach levels of about 4 ¢/kWh and below in the coming years (IRENA, 2019c). At electricity prices of 4 ¢/kWh, the production

Table 22. Cost of green hydrogen today and in the futures

	Historical progress	Where we are heading		Where we should be	
	2015-2018	2030	2050	2030	2050
Cost (USD/kg H_2)	4-8	2.5-5.0	1.6-3.3	1.8-3.2	0.9-2.0

Source: *IRENA (2020b).*

of hydrogen through electrolysis is about USD 2.5-3/kg. To make 1 t of methanol, 0.188 t of hydrogen are needed. At a cost of USD 3/kg, this represents USD 560 of hydrogen to make 1 t of methanol. According to IRENA and depending on the energy scenario, this cost should be USD 1.8-5.0/kg of green hydrogen by 2030 and USD 0.9-3.3/kg of green hydrogen by 2050 (IRENA, 2020a) (see Table 22). At USD 1/kg, making 1 t of methanol would only require about USD 190 of green hydrogen.

Cost of CO_2*:* The cost of CO_2 depends greatly on its origin and the amount of effort required to purify and compress it to the pressure needed for the synthesis of methanol. CO_2 fulfilling these requirements at the lowest cost, from around USD 20-30/t, can be obtained from facilities that already produce concentrated streams of CO_2, such as natural gas purification, fertiliser and bio-ethanol plants (Irlam, 2017). However, these sources have relatively limited capacity. A higher cost of between about USD 50 and USD 100/t of captured CO_2 (depending on technology and location) is incurred at power, steel and cement plants due to the need to add a carbon capture unit. The technologies for large-scale carbon capture at these facilities are relatively mature, but have yet to be applied on the enormous scale needed for the Power-to-X sector.

Most of these CO_2 sources are also not renewable or sustainable as they still rely on fossil fuels. Biomass can provide some of the required renewable CO_2 though BECCS/BECCU technologies. Costs can vary greatly between roughly USD 20 and USD 400/t CO_2, depending on the BECCS technology used, the nature of the feedstock, size of the plant, etc. (Fuss et al., 2018). Bio-ethanol production, biomass gasification and gasification of black liquor from paper mills offer some of the lowest-cost CO_2 at ~USD 20 to USD 100/t CO_2. Combustion BECCS that produces electricity had a somewhat higher cost, > USD 90/t CO_2.

Another source of CO_2 is the air. DAC technologies are being developed by a number of companies including Climeworks, Carbon Engineering and Global Thermostat. Costs are still high, in the order of USD 300 to USD 600/t CO_2, but are expected to decrease substantially to about USD 50-150/t CO_2 in the future as the technology is improved and scaled up (Fasihi et al., 2019; Sanz-Pérez et al., 2016, Keith et al., 2018). The cost of DAC is in great part related to the relatively low concentration of CO_2 in the air, presently around 420 parts per million. As pointed out in Section 2.2, the combination of bio-methanol and e-methanol production could also offer considerable synergies. Using green hydrogen to convert the CO_2 generated during bio-methanol production could avoid the need for CO_2 separation, reducing the cost of e-methanol production.

Table 23. Cost of CO_2 from various sources

Source or technology	CO_2 concentration in exhaust (%)	Estimated cost of CO_2 (USD/t CO_2)		Source
		Today	2050	
Fossil carbon				
Coal power plant	12-14	43-97	46-55	Irlam, 2017; IEA, 2012; Rubin et al., 2015
Coal power plant with oxy-combustion	Close to 100	52-75	52	Irlam, 2017; IEA, 2012
Natural gas power plant	3-5	80-89	43	Irlam, 2017; IEA, 2012
Iron and steel	20-30	55-77	40-65	Irlam, 2017; Leeson et al., 2017
Cement	15-30	35-125	20-103	Irlam, 2017; Leeson et al., 2017
Natural gas purification	2-65	15-25	20	Irlam, 2017; Leeson et al., 2017
Ammonia synthesis	Up to 100	20-25	24	Irlam, 2017; Leeson et al., 2017
Renewable carbon				
Biomass to ethanol plant	Up to 100	12-22	20	Irlam, 2017; Leeson et al., 2017
Biogas	40-50	~30	~30	Olsson et al., 2020
DAC	0.042 in air concentrated to close to 100	300-600	50-150	Fasihi et al., 2019; Keith et al., 2018; Sanz-Pérez et al., 2016
BECCS/BECCU	Close to 100	20-400	---	Fuss et al., 2018
Biomass gasification or biomethane reforming and conversion to methanol	Combined e- and bio-methanol production. No or limited CO_2 separation needed.	Integrated [(a)]	Integrated [(a)]	Described in Section 2.2: Combination of bio- and e-methanol production

Source: *IRENA (2020b).*

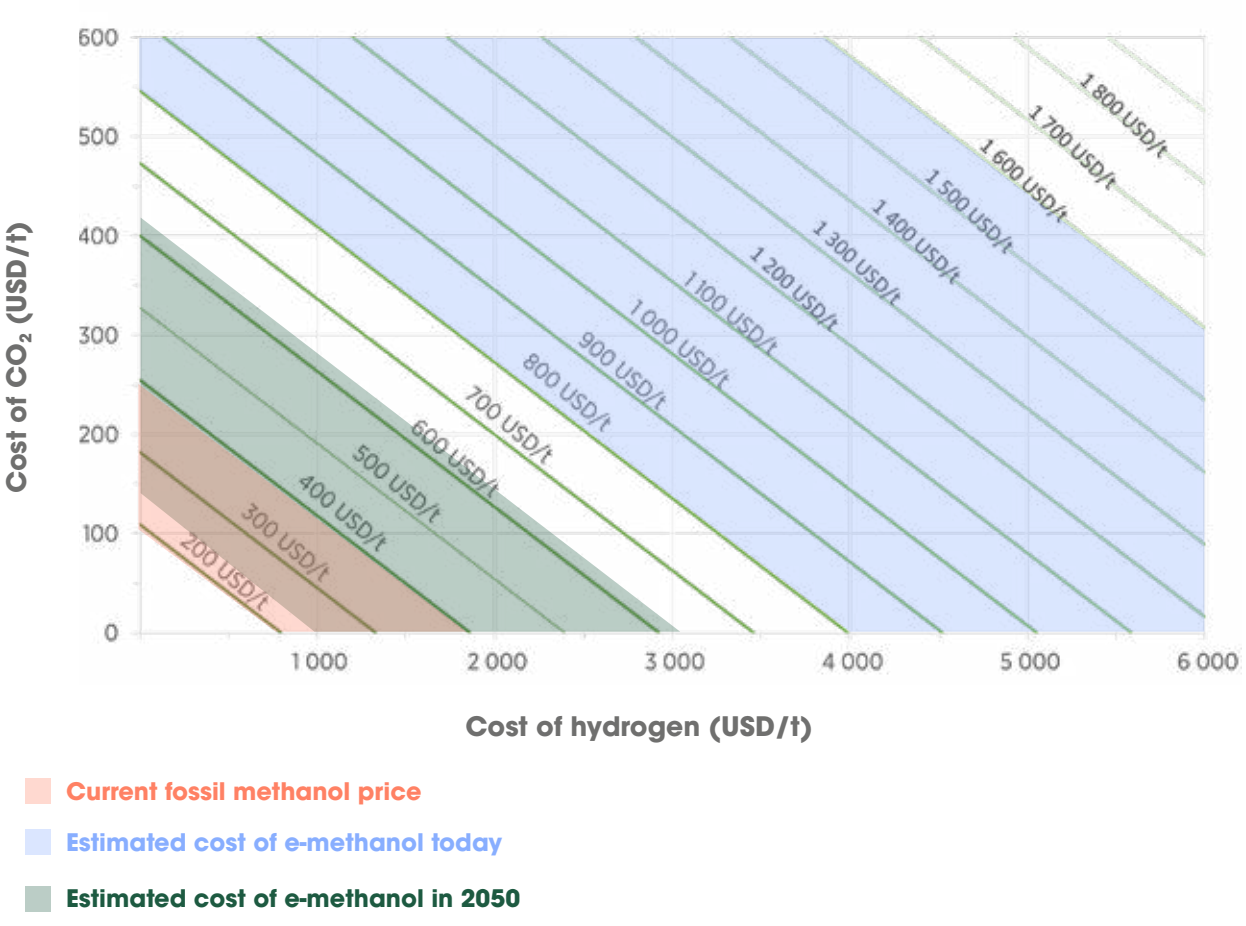
(a) The CO_2 is not separated in the process. H_2 from water electrolysis is added to use all or part of the CO_2 generated during biomass gasification.

Regardless of the origin of the hydrogen and CO_2, the cost of e-methanol production can be approximated by adding the cost of the hydrogen, the cost of the CO_2 and the cost to produce them in a large-scale methanol synthesis unit (estimated at USD 50/t e-methanol). As the results in Figure 6 show, these estimates are in the same range as those published in the literature and are highly dependent on the cost of the feedstock: H_2 and CO_2.

The cost of renewable methanol in the future can also be estimated from the projected cost of hydrogen and CO_2, as can be seen in Table 24 and Figure 40. The cost of hydrogen over time was taken from Table 11. The cost of renewable CO_2 depends on its source, as can be seen in Table 23 and Figure 30. At first relatively inexpensive CO_2 sources including bioethanol and biogas production will be used. These CO_2 sources, however, have limited availability. Therefore, as the production of CO2-derived fuels and materials such as e-methanol increases, costlier options will have to be progressively used. These include pulp and paper, waste-to-energy plants, biomass combustion and DAC, which offers the greatest potential. Availability and cost will also depend on competition with other CCU technologies as well as CCS.

Table 24 also shows that carbon credits can have a large impact on the cost of the renewable methanol produced. A carbon credit of USD 100/t CO_2 can reduce the cost of methanol by USD 172/t compared to no credit at all (based on avoided CO_2-eq emissions for e-methanol compared to methanol production from natural gas [Table 11]). As carbon credits are expected to become more prevalent in the future, this could play a significant role in making renewable methanol more competitive.

Figure 39. Cost of methanol as a function of hydrogen and CO_2 cost



Notes: *Assuming USD 50/t synthesis cost for e-methanol once the raw material H_2 and CO_2 are provided. Estimated cost of e-methanol today and in 2050 can be found in Table 24.*

Table 24. Estimated costs of renewable methanol up to 2050

		Estimated costs in		
		2015-2018	2030	2050
Cost of green hydrogen (USD/t H_2) [a]		4 000-8 000	1 800-3 200	900-2 000
Methanol through CO_2 from combined renewable sources				
Cost of CO_2 (USD/t CO_2) [c]		10-50	15-70	20-150
Cost of methanol (USD/t MeOH) [b]	With no carbon credit	820-1 620	410-750	250-630
	With a credit of USD 50/t CO_2 [d]	730-1 540	320-660	160-550
	With a credit of USD 100/t CO_2 [d]	640-1 450	240-580	70-460
Methanol through CO_2 from DAC only				
Cost of CO_2 from DAC (USD/t CO_2)		300-600	150-300	50-150
Cost of methanol (USD/t MeOH) [b]	With no carbon credit	1 220-2 380	600-1 070	290-630
	With a credit of USD 50/t CO_2 [d]	1 130-2 300	510-980	200-550
	With a credit of USD 100/t CO_2 [d]	1 040-2 210	420-890	120-460

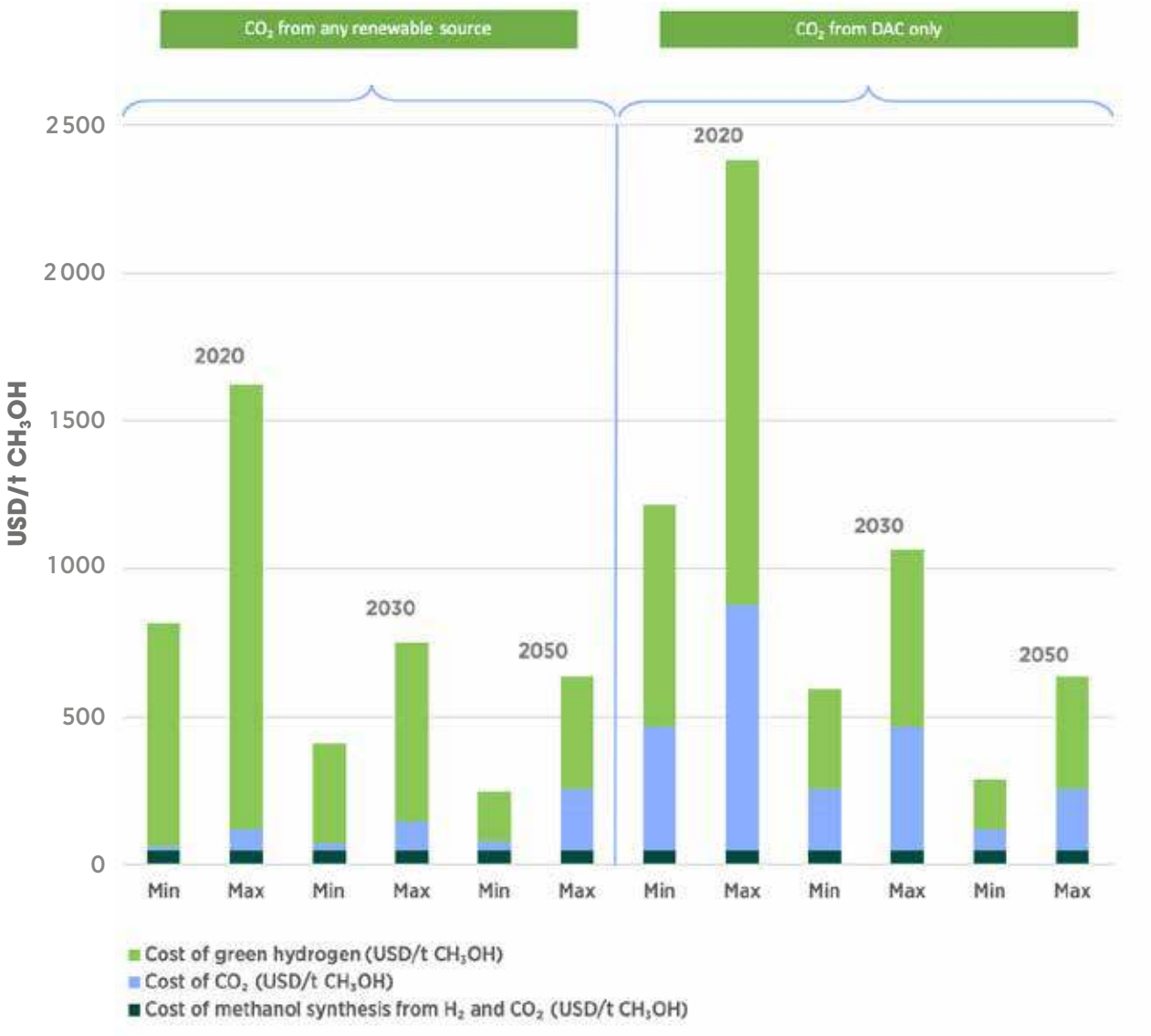
(a) Source: IRENA (2020b) using the "where we should be" assumptions in Figure S.6. Values reported in Table 11.

(b) Assuming USD 50/t synthesis cost for e-methanol once the raw material H_2 and CO_2 are provided.

(c) Origin of the CO_2 will change over time as volumes increase (see text for details).

(d) The carbon credit per tonne of e-methanol is based on the difference between the average CO_2-eq emissions from methanol production using natural gas (95.2 g CO_2-eq/MJ) and average CO2-eq emissions from e-methanol produced from renewable CO_2 and H2 (8.645 g CO_2-eq/MJ) given in Table 11. Considering an LHV of 19.9 MJ/kg for methanol, this corresponds to 1.72 tCO_2-eq of emissions avoided per tonne of e-methanol, compared to traditional natural gas-based methanol.

Figure 40. Estimated costs of renewable e-methanol up to 2050 depending on the renewable CO_2 source



Note: *CAPEX and OPEX for the production of hydrogen and CO_2 are already included in the respective cost of hydrogen and CO_2.*

Capital cost of e-methanol plants for current and proposed projects

Currently, only one commercial plant produces e-methanol; it is operated by CRI on a 4 000 t/y scale. The information available on capital cost is therefore very limited and mostly only for e-methanol projects and technology. This information is summarised in Table 25. The capital cost per unit of capacity is somewhat higher for the e-methanol plants, but is close to those reported in the literature in Table 21. They are, however, relatively high compared to the cost of natural gas-based methanol plants. It should be noted that most of the e-methanol plants considered to date are relatively small, with a production capacity of 12-300 t/d compared to world-scale natural gas- and coal-based plants, which usually have a methanol production capacity in the order of 2 500-5 000 t/d (mega-methanol plants). Small-scale natural gas-based methanol plants, too, have a higher cost per tonne of methanol produced (Sorensen, 2015). The cost per unit of capacity for e-methanol is thus expected to come down somewhat as the plants scale up and reach capacities similar to traditional methanol plants.

Table 25. Capital cost for CO_2-to-methanol plants

	Feedstock	Capacity (t/d)	Capacity (t/y)	CAPEX (million USD)	CAPEX (USD/ t/y)	Source
Thyssenkrupp	CO_2 and H_2	12	4 000	39	9 720	Thyssenkrupp, 2020b
FlexMethanol (bse engineering/ BASF)	CO_2 and H_2	~44	16 400	~50	3 100	bse engineering, 2019, bse Engineering, 2020
CRI (Norway)	CO_2 and H_2	300	100 000	200	2 000	Stefánsson, 2019
Swiss Liquid Future (Norway)	CO_2 and H_2	220	80 000	330-390	4 170-4 780	Swiss Liquid Future, 2020b
Typical plant based on natural gas	Natural gas	2 800	1 000 000	720-1 440	720-1 440	Bromberg and Cheng, 2010
Typical plant based on coal (US)	Coal	10 000	3 600 000	6 220	1 720	US DOE NETL, 2014

Reductions in electrolyser costs are especially important as they represent a large share of the investment. The cost of other parts of the plant including the methanol synthesis and distillation units, conversely, can exploit the reduced production costs associated with economies of scale. A "typical" or "standard" e-methanol plant is likely to be smaller than a current large-scale natural gas- or coal-based methanol plant.

Interestingly, CRI's estimated cost per t/y for the project in Norway is not much higher than for a coal-based methanol plant. It should also be noted that the capital cost includes the electrolysers, which represent a large share of the e-methanol plant cost.

It should also be pointed out that the capital cost generally only represents a minor proportion of the cost of e-methanol. The operating costs usually represent the largest share, mainly due to the cost of the electricity needed to produce the green hydrogen.

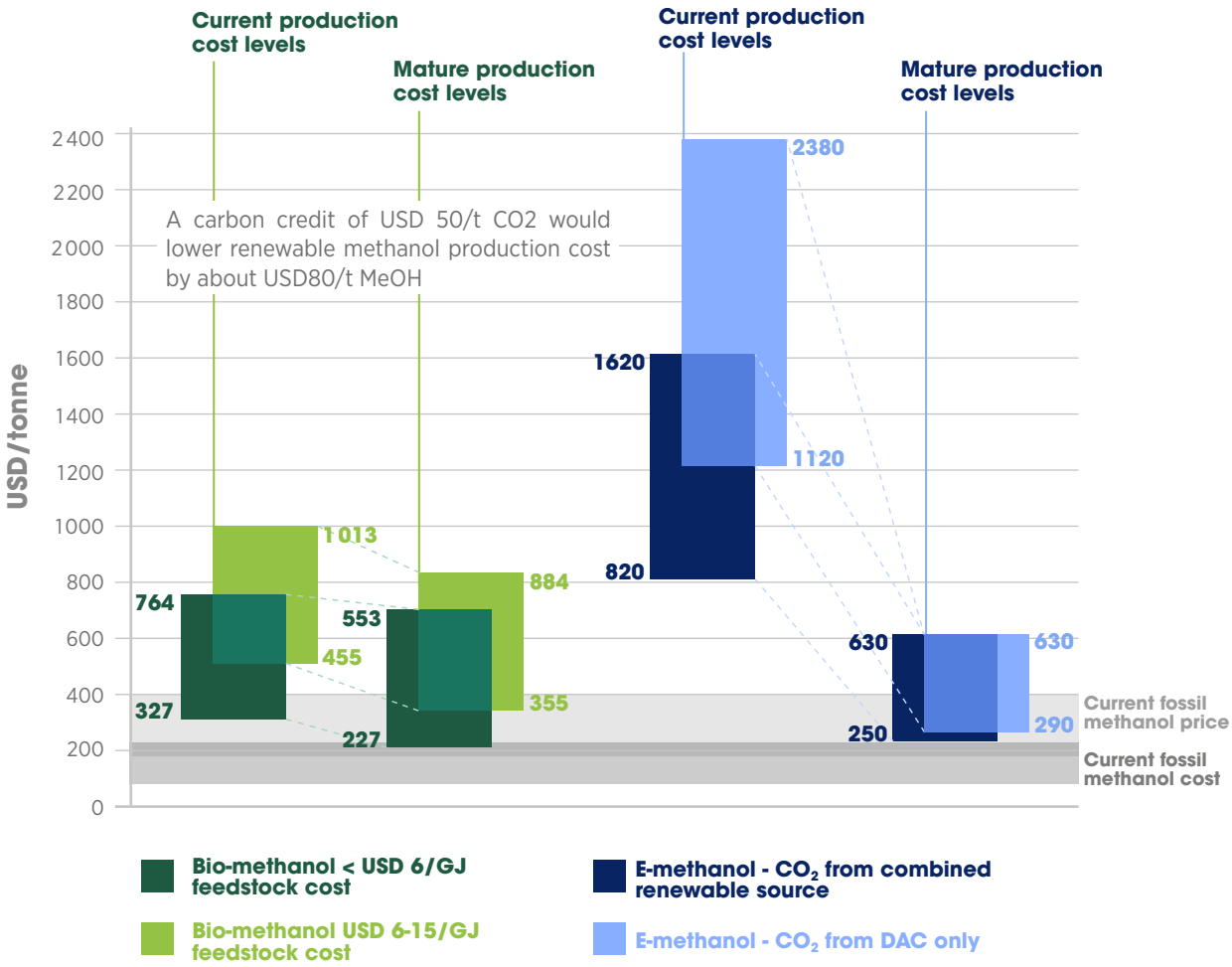
4.3. Summary of renewable methanol costs today and in the future

Compared to today's natural gas- and coal-based methanol production (with production costs as low as USD 100-200/t and USD 150-250/t, respectively), renewable methanol production costs in most cases are estimated to be higher. Methanol prices, on the other hand, have been fluctuating roughly between USD 200 and USD 400/t (when adjusted for inflation, average contract price for methanol in Europe, see Figure 8) (MI, 2020a; MMSA, 2020). Thus it should be noted here that fossil-based methanol is already competitive today with most petroleum oil-based fuels (gasoline, diesel, heating oil, etc.) on an energy content basis: USD 10-20/GJ for methanol compared to about USD 17/GJ for gasoline, diesel, jet fuel and heating oil (Figure 9). Production costs for bio-methanol and e-methanol are as follows:

- The cost to produce bio-methanol from biomass and MSW is estimated at between USD 327 and USD 764/t (Figure 41) with a feedstock price up to USD 6/GJ, which corresponds to the upper limit of biomass and MSW commodities currently used commercially in Europe and the United States. At a feedstock price range of USD 6-15/GJ, the production cost may increase to about USD 1 000/t. With process improvements, a cost of around USD 227/t to USD 553/t should be achievable for the lower feedstock price range up to USD 6/GJ and correspondingly higher for the higher price range. Production of bio-methanol from the waste streams of other industrial processes (e.g. black liquor from paper mills and MSW) in particular offer opportunities to simplify the feedstock logistics and improve overall plant economics. Co-production of heat, electricity or other chemicals has been suggested to further improve bio-methanol's economic performance. Another option is to co-feed biomass into a coal-based gasifier, or biogas into a natural gas-based methanol plant to allow for the gradual introduction of biomass as a feedstock and make methanol production more sustainable at a potentially lower cost.

- Current production of e-methanol based on hydrogen and CO_2 is estimated to be more expensive, approximatively USD 800-1 600/t (and possibly higher if CO_2 is obtained by DAC only). The cost of e-methanol depends to a large extent on the cost of hydrogen and CO_2. The cost of CO_2 will depend on the source from which it is captured (biogenic, DAC, industrial, etc.). The cost of hydrogen is strongly correlated with the cost of the electricity used to produce the hydrogen and the utilisation rate of the electrolyser units and electrolyser cost. With anticipated decreases in renewable power prices, the

Figure 41. Current and future production costs of bio- and e-methanol



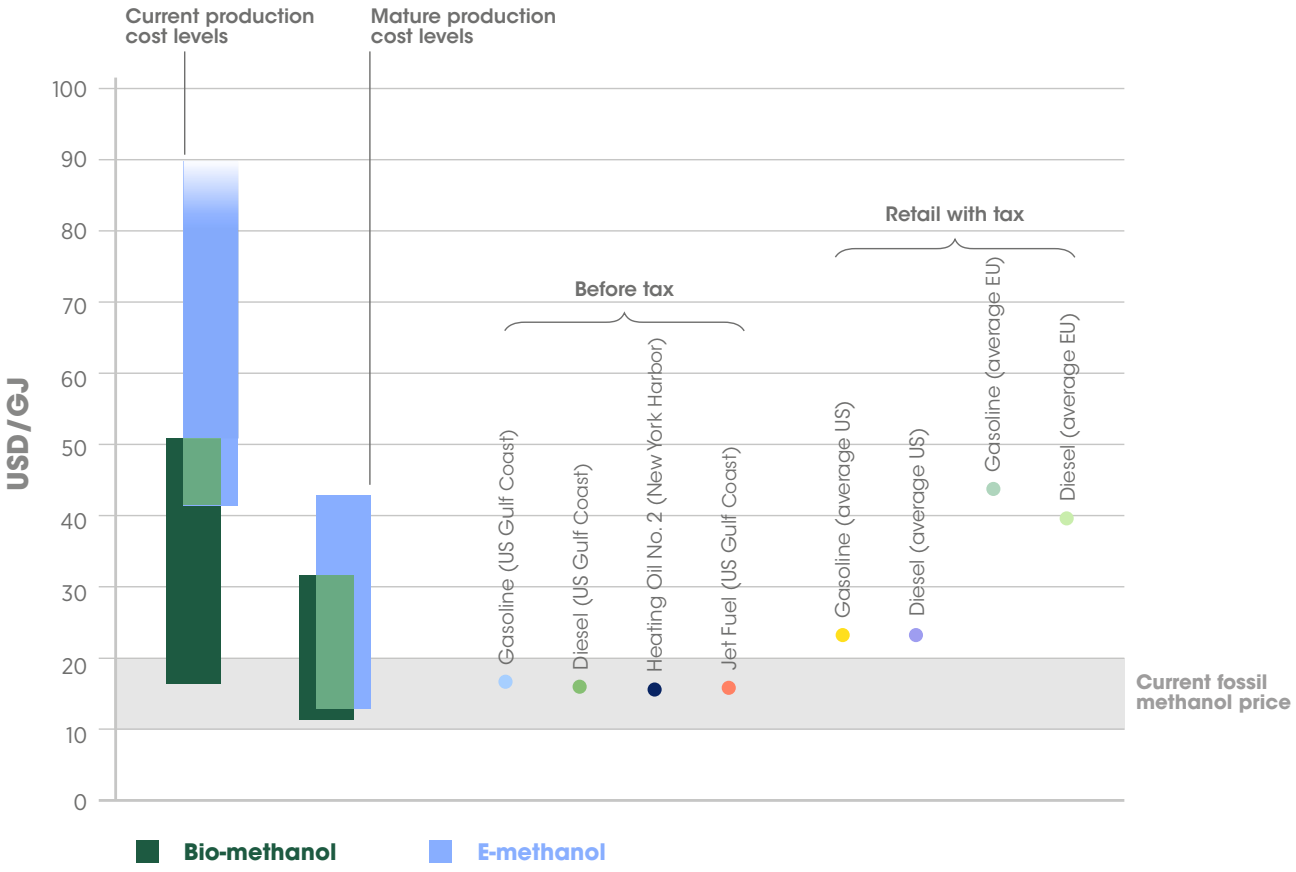
Note: *Exchange rate used in this figure USD 1 = EUR 0.9.*

cost of e-methanol is expected to decrease as well to reach levels of USD 250-630/t without CO_2 credits by 2050. As in the case of bio-methanol, co-production of brown/grey (fossil) and green e-methanol might be a way to gradually introduce green e-methanol at a reasonable cost.

In the case of both bio- and e-methanol, part of the higher cost is also due to the smaller scale of the plants. Nevertheless, the cost projections for renewable methanol by 2050 are within the range of current fossil methanol and petroleum-based fuels and products, as can be seen in Figure 41 and Figure 42. By 2050, a production cost of about USD 11-43/GJ and USD 12-32/GJ is estimated for bio- and e-methanol, respectively.

The application of carbon credits could also lower substantially the cost of both bio- and e-methanol. Compared to the production of methanol from natural gas, a decrease in CO_2-eq emissions of about 1.6-1.7 t per t of renewable methanol was estimated. This means that for every USD 1 credit per t of CO_2-eq avoided, a decrease in methanol cost of about USD 1.6-1.7/t of methanol could be expected. This means that for, example, with a credit of USD 100/t CO_2-eq, a cost reduction for renewable methanol of USD 160-170/t could be reached.

Figure 42. Comparison of renewable methanol with other fuels on a price per unit of energy basis



Note: *Exchange rate used in this figure USD 1 = EUR 0.9. Fuel costs and prices are averaged over 10 years. See annex 3 for details.*

5. POTENTIAL AND BARRIERS

5.1. Demand

Methanol, whether from fossil fuels or renewable sources, has the same chemical structure: CH_3OH. As such, renewable methanol could in principle replace fossil methanol in any of its current uses, for example as a feedstock for the production of various chemicals, materials, plastics and products and as a fuel for transport, shipping, cooking, heating and electricity production. In addition, renewable green methanol could replace most fossil fuel-based hydrocarbons and petrochemicals either directly or through methanol derivatives for a potential market in the hundreds of millions of tonnes and possibly billions of tonnes of methanol per year. Annual global methanol production is expected to grow from its current 100 Mt to more than 120 Mt by 2025 (MMSA, 2020; Berggren, 2019) and 500 Mt by 2050 (Saygin and Gielen, forthcoming).

Most of the growth to 2028 is expected to occur in China, and more specifically the demand to be for MTO and a smaller share for gasoline blending, formaldehyde, acetic acid and MTBE. The chemical sector will thus continue to play an important role in methanol demand growth. Looking ahead, however, the increase in methanol production is expected to see a progressive shift to renewable methanol, with an estimated annual production of 250 Mt of e-methanol and 135 Mt of bio-methanol by 2050 (please see insert below and Figure 47).

The introduction of green methanol would allow for a transition to a sustainable circular green economy in the chemical industry, the transport sector and other energy-related sectors. Of course, in practice the expansion of renewable methanol is currently held back by its higher production cost when compared to natural gas-based methanol. Renewable methanol, however, is still one of the easiest to implement sustainable fuels and a promising feedstock in the chemical sector, and costs are expected to continue falling as discussed in Chapter 4 of this report.

As with any other alternative fuel and chemical feedstock, for renewable methanol to take off demand has to be stimulated by adequate policies, regulations and mandates. In the European Union the RED II directive, for example, mandates that 14% of the energy used in transport should come from renewable sources by 2030. Other nations are also increasingly requiring part of transport fuels to come from renewable sources. The markets for renewable methanol to date are therefore mainly concentrated in the transport sector where regulations mandate the use of greener alternatives to reduce emissions.

Vulcanol, produced in Iceland from CO_2 and H_2 by CRI, and bio-methanol produced by BioMCN in the Netherlands, are used as a fuel additive in Europe. In 2018, 57 million litres of bio-methanol were blended with gasoline in the United Kingdom (Dolan, 2019). Renewable methanol can also be used for the production of biodiesel. In the near term, assuming that the M3 standard (3% methanol by volume in gasoline, EN 228) is implemented across the European Union (approximately 82 Mt gasoline in 2019), about 2.5 Mt of renewable methanol would be required (CRI, 2019; Fuels Europe, 2020). In the longer term, renewable methanol could address part of the fuel needs for all cars, trucks, ships and so on (gasoline, diesel, marine fuels, etc.). This is a market of 350 Mt of oil equivalent (~700 Mt of methanol on an energy basis) in Europe and about 2 billion t in the world.

While other options are increasingly available for light passenger cars (e.g. batteries, hydrogen), alternatives for heavy trucks and shipping are limited. These hard-to-electrify sectors are well-suited to the use of renewable methanol (van Kranenburg et al., 2020). Renewable methanol either pure or mixed with gasoline is an excellent fuel for ICEs (Figure 43 and Figure 44). Methanol can also be used as a marine fuel, in modified diesel trucks and in hybrid and fuel cell-powered vehicles

and ships (Figure 11 and Figure 46). DME, an easily obtainable methanol derivative, is itself a superior fuel for compression ignition engines (diesel-type engines, Figure 45). The currently observed expansion of fossil methanol as a fuel in many applications could ease the gradual transition to renewable methanol as the distribution and transport infrastructure would remain unchanged. At the same time, demand for renewable methanol in the chemical industry should also be stimulated with various policies including incentives, mandates and carbon taxes, in order to make this hard-to-electrify sector greener and eventually carbon neutral.

Figure 43. Fleet of Geely Emgrand 7 cars operating in Iceland and powered by 100% renewable methanol, in front of the CRI CO_2-to-methanol production plant

Source: *CRI (2020).*

Figure 44. Swedish car powered by an M56 mix (56% methanol in gasoline) with bio-methanol from the LTU Green Fuels plant (in the background)

Source: *Rikard Gebart, LTU Green Fuels.*

Figure 45. Chemrec bioDME pilot plant and Volvo DME-fuelled truck

Source: *Courtesy of Maria Fäldt.*

Figure 46. Passenger ship MS innogy on Lake Baldeney (Germany) powered by a hybrid fuel cell system fuelled by renewable methanol

Source: *Stadt Essen, Peter Prengel.*

RENEWABLE METHANOL PRODUCTION FORECAST

IRENA is projecting that global methanol production would increase from 100 Mt currently to 500 Mt in 2050 (Saygin and Gielen, forthcoming) based on the Transforming Energy Scenario. This increase would also need to be accompanied by a shift to renewable methanol (Figure 47). In 2050, 250 Mt of e-methanol and 135 Mt of bio-methanol are estimated to be produced annually; this is an ambitious yet realistic transformation pathway built on renewable energy and steadily improving energy efficiency.

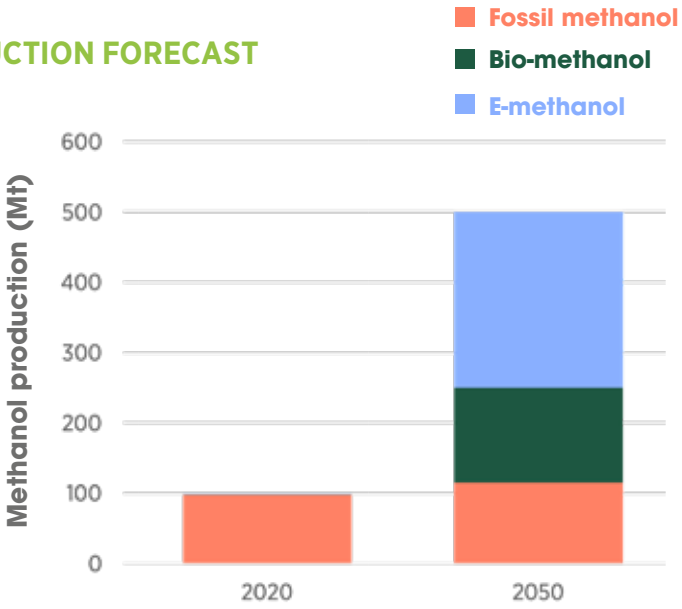


Figure 47. Current and future methanol production by source

E-METHANOL: To produce 250 Mt of e-methanol will require about 350 Mt of CO_2 and 48 Mt of hydrogen. To produce this quantity of hydrogen through water electrolysis and assuming consumption of 50 MWh/t of hydrogen produced, about 2 400 000 GWh of electricity would be needed, corresponding to 8.6 EJ. This would require about 275 GW of continuous electricity production, as well as 280 GW of electrolyser capacity. In terms of solar power, installed capacity of about 920 GW (at a capacity factor of 30%) would thus be required. In the case of wind power, about 500 GW of installed capacity (at a capacity factor of 55% as encountered in some offshore wind farms) would be called for.

Various combinations of these and other renewable power sources could be applied. The required CO_2 will be recycled preferably from renewable biogenic sources or DAC. About 280 methanol plants with a capacity of 2 500 t/d (900 000 Mt/y) will need to be constructed to produce 250 Mt/y. The construction of an e-methanol plant takes about 2-3 years to build, or less if modularised and standardised. Production of e-methanol from CO_2 and H_2 is very similar to current production of methanol from fossil fuel-based syngas and thus relatively mature and scalable. Scale-up of water electrolysis technology to the gigawatt scale is under way and should be widely available in the near future for large-scale green hydrogen generation.

BIO-METHANOL: To produce 135 Mt of bio-methanol through gasification will require 4.1 EJ of biomass material, which equals about 230 Mt of dry biomass. The global biomass potential is estimated at 97-147 EJ by 2050 (IRENA, 2014). Due to the nature of biomass and cost of collecting and storing the feedstock, a typical biomass-fed bio-methanol plant is assumed to produce 300 kt/y. As a result, there would be a need of 450 plants of that size to produce 135 Mt/y of bio-methanol. It would require an investment of about USD 130 billion.

If renewable hydrogen is added to gasification-based plants in order to utilise all in situ available renewable carbon, partly in the form of CO and partly CO_2, bio-methanol production could reach 290 Mt/y using the same biomass source, 4.1 EJ. This would require approximately 26 Mt/y of hydrogen, which would need production of 1 300 000 GWh of renewable electricity (4.7 EJ). The typical plant size would as a consequence increase to about 650 kt/y. A gasification-based plant of the quoted size will take 20-24 months to build from letting of contract to the point when the plant is ready for start-up.

5.2. Sustainable feedstock

Biomass

In the United States, around 300 Mt/y of unused (dry) biomass are available today, and potentially 750-1 000 Mt/y could be available in 2040, two-thirds of this from energy crops that are not cultivated currently (US DOE, 2016). In Europe, an estimated 1 050-1 370 Mt/y of sustainable (dry) biomass could be available by 2030, of which 525-850 Mt/y would be available after meeting other demands (S2Biom, 2016). These volumes constitute the sum of different types of agricultural residues, additional biomass from sustainable forestry, wastes (the lignocellulosic fraction after recovery and recycling) and industrial crops on released agricultural land.

Production of bio-methanol based on the above summarised maximum feedstock resources in the United States and Europe (in 2030-2040), and converted using a conversion efficiency of 65%, would result in a production potential of 1 100 Mt/y. Utilising the combined bio- and e-methanol concept described in this report would increase this by a factor of about 2.15, to 2 350 Mt/y of methanol or about 50 EJ/y.

Taking a global perspective the potential for sustainable biomass in 2030 has been estimated to be 97-147 EJ/y (based on total minimum and total maximum scenarios) (IRENA, 2014). However, there is a substantial potential to sustainably expand the bioenergy supply (IRENA, 2016b).

Calculated as above and based on IRENA (2014), this global potential (including the United States and Europe) corresponds to 3 200-4 800 Mt/y of methanol with a conversion efficiency of 0.65, and to 6 900-10 400 Mt/y of methanol (147-218 EJ/y) if combined bio- and e-methanol processes were fully implemented. By comparison, the world's total oil consumption in 2019 was 188 EJ/y (BP, 2020). Naturally, these figures are only illustrative of the potential for bio-methanol production. Presumably, not all potentially available biomass would be utilised solely for the production bio-methanol.

Waste and residues from forestry and agriculture have greater availability and would represent the bulk of the raw materials for advanced biofuels. So-called energy crops can also be grown, preferentially on land that is not used for food or other crops such as contaminated and marginal land.

To be sustainable these crops would also have to comply with a number of other criteria, including impact on soil quality, soil erosion, need for water and fertilisers, biodiversity concerns, land tenure and emission of pollutants to air and water.

CO_2 and hydrogen

For the production of e-methanol, sustainable sources of both H_2 and CO_2 are required. Hydrogen is already produced on a large scale of about 120 Mt/y, of which two-thirds are pure hydrogen and one-third is in mixture with other gases (IRENA, 2019d; IRENA, 2018). A mixture of hydrogen with other gases is used, for example, in methanol and iron/steel production. Pure hydrogen is essential for various industrial processes, mostly petroleum refining and ammonia synthesis. However, over 95% of it comes from fossil fuels and only about 4% is presently supplied via electrolysis (IRENA, 2018). To be sustainable in the long term, most hydrogen will have to be produced from renewable energy sources, and will thus depend on the cost and availability of these resources. While any renewable source can be used, solar and wind are the renewables with the highest potential for expansion to the size needed for large-scale deployment of e-methanol

Technology for the electrolysis of water with alkaline electrolysers is already available on the 100 MW scale for the chloralkali process. A new generation of alkaline electrolyser dedicated to green hydrogen production is being developed, with slightly different features, although the fundamentals remain similar. Both alkaline and PEM electrolysers are already commercial at the megawatt scale, with facilities coming on line combining multiple stacks to reach tens of megawatts, quickly moving towards hundreds of megawatts per single facility.

The potential for green hydrogen production will mainly depend on the combination of further reductions in the cost of renewable power generation and electrolysers, and gains in efficiency and durability. Carbon dioxide is in a situation similar to hydrogen. A lot of CO_2 is emitted by industrial sources and fossil power plants that are overwhelmingly powered by fossil fuels. The recycling/upcycling of these CO_2 emissions to blue methanol

using green hydrogen does not result in an increase in atmospheric CO_2 when methanol is used or combusted. Blue methanol could thus already be considered as a low-carbon fuel.

Using the CO_2 from fossil fuel sources one more time to produce methanol instead of simply releasing CO_2 to the atmosphere could potentially halve the overall emissions. However, while these sources of fossil CO_2 can be certainly used to produce methanol in the transition phase, to be at the same time carbon neutral and sustainable the CO_2 will have to be sourced from renewable sources, i.e. from biomass and via DAC at a reasonable cost. BECCS/BECCU can already be applied today. DAC, although promising, is still at the early stages of development (Goeppert et al., 2014; Sanz-Pérez et al., 2016). The amount of CO_2 available in the air is for all practical purposes unlimited and its economic extraction will only depend on the availability of a suitable DAC technology and inexpensive renewable electricity.

5.3. Impact of renewable methanol on the energy sector

The progressive defossilisation of the energy, industrial and chemical sectors and their concomitant electrification through the use of renewable energy sources will have profound effects. Hourly, daily and seasonal fluctuations and intermittency in the generation of electricity from variable renewable energy sources will need to be increasingly dealt with to maintain a stable and reliable grid. In this context the production of electrofuels and electrochemicals can help stabilise the grid by providing an outlet for renewable power when supply is higher than demand. Dynamic e-methanol plants able to "follow the load" in the electric grid and adjust their methanol output accordingly are also being specifically developed for that purpose.

The production of e-methanol offers a way to increase the value of green power and store electricity in a convenient liquid that can be easily kept for later use. For larger e-methanol plants, dedicated renewable energy generation capacity will probably have to be built. Demand for such large production facilities should further lower the cost of renewable power and the materials produced with that power. Producing renewable methanol, as well as downstream products including polyethylene, polypropylene and various other polymers and materials, could also be a way for renewable energy-rich regions such as Australia, the Middle East and Northern Africa to export this resource in a convenient form, while benefiting their economies and the planet.

5.4. Drivers

The main driver for the production of renewable methanol is the need to decouple society from its dependence on fossil fuels, which are the major source of GHG emissions and associated environmental issues. Sustainable and durable solutions based on renewable resources are thus needed. In this energy transition, renewable methanol can act as a new energy carrier to reduce and eventually eliminate the carbon footprint of the chemical/petrochemical and energy sectors.

To drive the change towards a sustainable future, strong policies and regulation will be needed to push the production and use of renewable fuels and materials. The European Union's Energy Roadmap calls for GHG emission reductions of 80-95% by 2050 (EU, 2012b). This will require a complete overhaul and transformation of the energy sector, where about two-thirds of energy will have to come from renewable sources. A similar transition will be needed in most of the world to ensure a secure, competitive and sustainable energy system for the long run (IRENA, 2019c). According to IRENA, 70% of the world's energy-related CO_2 emissions need to be cut by 2050, and eventually to zero beyond that (IRENA, 2020b). This is a unique opportunity for the development of renewable methanol as a part of the solution.

Compared to other bio-based materials and fuels, bio-methanol and bio-DME have, together with BioSNG and biomethane, the lowest production costs, considerably lower than cellulosic ethanol and FT-type products (Maniatis et al., 2018; Brown et al., 2020).

Brown or grey methanol from fossil fuels is already a large-scale commodity chemical and fuel. Chemically identical

LCM, blue methanol and green methanol could easily replace brown or grey methanol in any of its applications. All of these lower carbon footprint methanol types are ideal raw materials for the chemical industry for the production of materials and products, such as plastics, clothing, bottles and paint. They are also superior fuels for cars, trucks, ships and hard-to-electrify sectors.

The key benefits and drivers of renewable methanol include:

- versatile intermediate for the production of numerous chemicals and materials
- can be produced with low GHG emissions
- easy to produce from a variety of sustainable feedstocks such as biomass, MSW or CO_2 and H_2
- a liquid that is easy to store, transport and distribute
- compatible with existing distribution infrastructure and can partly be blended with conventional fuels
- leads to a reduction in other harmful emissions (SOx, PM, NOx, etc.)
- liquid hydrogen carrier.

The greening of the industrial sector, especially the chemical and petrochemical industries, although challenging, should be a main driver for renewable methanol. Renewable methanol can be a feedstock for existing products currently obtained from fossil methanol. In addition, renewable green methanol could find new uses and replace most petroleum-based hydrocarbons and petrochemicals either directly or through methanol derivatives for a potential market in excess of a billion tonnes of methanol per year. Production of plastics and aromatics (BTX) from renewable methanol could, for example, be greatly expanded (Bazzanella and Ausfelder, 2017). For example, each car currently produced in Europe requires about 300 kg of methanol for the production of various parts (Seuser, 2020). If the methanol used was renewable, it could already considerably reduce the carbon footprint of the automotive industry.

The ground and sea transport sectors are also likely to be a main driver of the expansion of renewable methanol, due to mandates and legislation being increasingly put in place by regulating authorities to reduce GHG emissions and achieve sustainability goals. The International Maritime Organization, for example, aims to halve the CO_2 emissions from shipping by 2050 (IRENA, 2019b). Other options exist for the greening of light-duty passenger vehicles, including batteries and hydrogen. However, the electrification of heavy-duty trucks, ships and other heavy equipment is more challenging. For these hard-to-electrify transport sectors, renewable methanol and its derivatives can be good options.

In the case of e-methanol, and electrochemicals and electrofuels in general, one of the inherent drivers is also the availability of inexpensive renewable power. As fossil fuel-based industry and power generation are increasingly scrutinised, permitting and licences to operate should become relatively easier to obtain and maintain for projects that include a significant green component. From an energy security point of view, the possibility of producing renewable methanol locally with any available biomass and renewable power is attractive too. Island-type projects where renewable energy can be produced relatively cheaply, but the import of fuels is costly, could be good candidates for local production of green methanol. Production of renewable methanol would also stimulate global trade between renewable energy-rich regions such as North Africa and the Middle East (solar power) and energy-importing regions such as Europe, North America and Asia.

5.5. Barriers

The main barrier to the adoption of renewable methanol is the same as for some other renewable alternative fuels and feedstocks, namely the cost of production. In that sense, policies to stimulate and sustain the production and use of renewable methanol on a large scale are needed. These are discussed in more details in the policy section.

Bio-methanol

Although the production cost of bio-methanol is lower than for e-methanol, in most cases it remains higher than the cost of grey methanol from natural gas and to a lesser extent coal. This is basically the case for all fuel and chemical commodities that could substitute for their

fossil counterparts. Bio-methanol, however, has one of the most attractive production costs compared to other alternatives, as shown in two recent studies (Brown et al., 2020; Maniatis et al., 2018).

Capital costs for most advanced renewable fuel plants are relatively high and they remain difficult to finance. Even projects that have successfully demonstrated their technology, and have mitigated and allocated all their risks (technology, commercial etc.) are having difficulty securing financing for commercial-scale rollout. One of the problems is that policy makers usually provide only short-term and/or quota-based schemes, which cannot support the long-term price floor required for successful implementation of advanced renewable fuels. The successful roll-out of renewable electricity was based on feed-in tariffs, contracts for difference or similar instruments that meaningfully address risk barriers. Similar schemes should be made available for bio-methanol and e-methanol.

In the long term, biomass will be able to cover a substantial share of global energy needs, but it has also a number of limitations (IRENA, 2016b; IRENA, 2017). These include (among others) land availability, competition with other crops including food crops, impacts on soil quality, soil erosion, need for water and fertilisers, biodiversity concerns, land tenure and emissions of pollutants to air and water.

The requirement to collect biomass over a large area to supply bio-methanol plants could also mean that these plants remain smaller than current world-scale methanol plants. This means that bio-methanol plants would have to be optimised for that scale. In addition, seasonality of the biomass feedstock needs to be addressed either by storage or feedstock diversification in order to minimise plant idling or shut down.

E-methanol

The main barrier to e-methanol production from CO_2 and H_2 is its cost and more specifically the cost of providing the hydrogen through the energy-demanding water electrolysis step. About 50 MWh of electrical power is needed to produce each tonne of hydrogen. This process is, in turn, directly correlated with the cost of the electricity used to run the electrolysers. As for most electrofuels, lowering the cost of electricity is thus the number one driver for lowering the cost of e-methanol from its current USD 800-1 600 per tonne. As renewable energy costs are expected to continue decreasing in the future, the cost of hydrogen and therefore e-methanol should follow the same trend and reach levels closer to USD 250-630/t without CO_2 credits, and below that with credits. Besides electricity cost, electrolyser costs also need to decrease further and large sources of reasonably priced renewable CO_2 secured.

Production of methanol from CO_2 and H_2 is not limited by technology. The almost identical, proven and fully commercial technologies used to make methanol from fossil fuel-based syngas (TRL 9) can also be used for e-methanol production. Electrolysis of water and CO_2 capture technologies are also available at a sufficient level of maturity. From a technological viewpoint it is entirely possible to have an e-methanol plant of the same size as a conventional methanol plant, i.e. 1 000-5 000 t/d, as the technologies are comparable. The difficulty would mainly be in finding the required feedstock at a reasonable cost and capital to build the plant. Technically the production of e-methanol is not limited by these factors.

Intermittency and fluctuations in power output from solar and wind energy need to be managed to allow for the e-methanol plant to operate most of the time. For this, a robust and reliable electrical grid will need to be developed. Some combination of solar, wind, hydro and geothermal, as well as storage of energy or hydrogen, could be envisioned. The development of e-methanol plants able to handle dynamic fluctuation in electricity power generation from solar and wind resources could be advantageous.

In the short term CO_2 can be obtained from various industrial sources and fossil fuel-burning power plants at costs around USD 50-100/t. However, to be really renewable and net carbon neutral, e-methanol will increasingly have to be made from biogenic CO_2 sources or CO_2 from the air through DAC. While almost pure CO_2 can be obtained from ethanol plants, these sources are limited. Other biogenic sources have to be further

developed to supply CO_2 reliably and at an acceptable cost. A hybrid bio- and e-methanol plant in which the syngas obtained from biomass is complemented with green hydrogen is a sensible solution to this problem. The cost for CO_2 obtained through DAC will also have to come down considerably to become an economic option for e-methanol production.

A progressive greening of methanol production is probably an appropriate pathway to introduce renewable methanol. Some of the "blue" methanol technologies being implemented today to produce what is called LCM are very important, especially the production of green hydrogen to supplement the production of methanol from natural gas. This should allow the electrolysis technology to scale up to the hundreds of megawatts. Once these large electrolysers are standard and low cost, large-scale production of green methanol would be much easier to introduce. The production of H_2 is the number one cost driver for e-methanol. All that is needed at that point is sufficiently low renewable electricity prices.

This seems to imply that for renewable methanol to be used in commerce at any appreciable rate, much higher levels of regulatory support will be needed, for example through an increased carbon price or subsidisation of the product price. Neither of these are technical issues, but instead require a level of political will that is still not evident in most jurisdictions.

5.6. Policies and recommendations

Crafting the right policies and incentives is crucial to meeting the goals of carbon emission reduction, energy security, sustainability and improvement in quality of life. Sufficient investment in long-lived capital-intensive renewable technologies will not happen without confidence in strong, stable, predictable and sustained government policy.

In the transport sector, much of the policy focus is on electromobility and support for increasing the share of EVs, especially for passenger cars. However, batteries and hydrogen fuel cells may be challenged in meeting the energy demands of long-haul trucking, shipping and aviation. Further, the legacy fleet of combustion engines will continue to power cars, trucks, buses, ships and aircraft for years to come even as electromobility makes market inroads and charging infrastructure expands.

Besides batteries that have a relatively low energy density, energy-dense fuels that store their energy in the form of chemical bonds – such as bio-methanol and e-methanol – also offer low-carbon and net carbon-neutral alternatives to traditional fossil fuels. Renewable methanol can today be mixed with fossil fuels and used in existing combustion engines and current refuelling networks, providing immediate benefits for GHG emission reductions. The increasing substitution of gasoline and diesel fuels with renewable methanol over time would enable a transition to low-carbon and net carbon-neutral transport.

Similarly, as a basic building block for hundreds of chemicals that touch our daily lives, the transition towards renewable methanol can contribute to the circular economy and the adoption of green chemicals.

Renewable methanol can facilitate sector coupling. Renewable electricity from the power sector or biomass from the agriculture sector can be used for e-methanol and bio-methanol production to fuel transport and industrial-sector energy demands. Each sector may find a different pathway to carbon neutrality, and public policy should create a level playing field to expand and not limit opportunities.

A technology-neutral approach in mobility would place an emphasis on carbon intensity rather than whether propulsion came, for example, from batteries or from fuel cells fuelled with green hydrogen or renewable methanol. Such an approach needs to be supported by political will and translated into regulatory measures for fuel standards and approval of new fuels accounting for the carbon footprint of the targeted market.

Legislation and standards for methanol used as a fuel for road transport are already in place or being put in place in many countries. Some examples can be found below. While these were initially intended for fossil fuel-based methanol, they also apply to renewable methanol and will ease the transition.

Over the last 15 years, various provinces in China introduced standards for methanol blends in transport, going from 5% methanol in gasoline (M5) all the way to 100% methanol (M100). China's central government has adopted a policy paper supporting the commercial introduction of M100 cars, trucks and buses. Israel established an M15 standard in 2016. Other countries that are either introducing or evaluating the introduction of methanol blending in gasoline include Egypt (M15), India (M15), Italy (M15/E5), New Zealand and Trinidad and Tobago (M5) (Klein, 2020; Dolan, 2019). Standards for high methanol blends and pure methanol (M100) need to be put in place in more countries. Many countries have only implemented methanol blending standards for low-level methanol blends (M3-M5), including the European Union (EN 228 standard, 3% methanol) and the United States (Kramer, 2018). Refuelling stations dispensing methanol are identical to today's fuelling stations dispensing gasoline and diesel fuel. In most cases, after proper cleaning, the same storage tanks can be used. Some changes to the refuelling lines, gaskets and so on might be needed to accommodate methanol, but the changes are in general minimal, low cost and do not require much time to complete.

To overcome the barriers linked to the introduction and development of renewable methanol, robust policies directed towards renewable fuels will be needed. Government mandates for fuel blending quotas, incentives for renewable fuels, and carbon taxes would have an impact on the willingness of the market to pay a premium for renewable methanol. Over 60 countries have put renewable fuel targets or mandates in place. In the European Union, the policy driver is the Renewable Energy Directive (RED), with a recent 2018 recast (RED II) requiring 14% renewable energy to be used in transport by 2030. First-generation biofuels will be phased out, initially capped at 7%, then reduced to 3.8% by 2030, and ultimately eliminated, opening opportunities for bio- and e-methanol. A report by Siemens notes that about a quarter of renewable energy in transport will come from electromobility, and coupled with the limits on first-generation biofuels, e-fuels will be needed to meet European targets, and much of that will be imported from outside of Europe (Schnettler et al., 2020). The EU RED II and Fuel Quality Directive classify renewable methanol from non-biological origin (e-methanol) as a renewable fuel. Other EU policies that also influence the uptake of renewable methanol are (among others) the Alternative Fuel Infrastructure Directive and the Air Quality Directive.

While e-methanol would qualify as a renewable fuel of non-biological origin, RED II places barriers to the purchasing of renewable electricity from the grid that must be overcome. The specification of a direct correlation in time and geography of synthetic fuel production and renewable electricity generation is a barrier to both investment and e-fuel uptake, as noted by the Working Group Power-to-X Applications (VDMA, 2020). Guarantees of origin and purchase power agreements should be adequate proof that renewable electricity from a wind turbine or solar farm in one location has been purchased by a producer of e-methanol in another location connected by the transmission grid. Concepts such as "virtual power plants" can allow for real-time monitoring and validation of both manufacturers and consumers to avoid double counting of the renewable power feedstock. This "mismatch" between the goals of RED II and its implementation must be corrected.

As an e-fuel, e-methanol can be produced in regions with ample resources of renewable electricity, using carbon as a carrier in the form of an easily transportable liquid molecule. Investing in e-methanol production capacity in different countries around the world will diversify energy supply and reduce political risks. To make this a reality, international co-operation will be needed, including import strategies to harness the world's best feedstock locations for wind and solar energy. A perfect example is the collaboration between Europe and Morocco to promote Power-to-X, including e-methanol production in Morocco for export to Europe, with the additional benefit of creating a new market for European-based technology for synthetic fuel production (Engelhardt, 2020). Such international co-operation can create jobs and new competitive industries in both the e-methanol producing and consuming regions.

The United Kingdom introduced its Renewable Transport Fuel Obligation scheme in 2008. Fuels that are categorised as Renewable Fuels of Non-Biological Origin

such as e-methanol, are incentivised by awarding double credits per litre or kilogram supplied. These credits are known as Renewable Transport Fuel Certificates and can be traded between suppliers of fossil transport fuels or eligible biofuels. In 2018, 57 million litres of bio-methanol were blended with gasoline in the United Kingdom. In the United States, the Renewable Fuel Standard, established in 2005, mandates the use of biofuels in the transport sector. Bio-methanol, if approved, could meet the requirement for cellulose-based biofuel or advanced biofuel. In California the Low Carbon Fuel Standard (LCFS) was introduced in 2011 to promote the use and production of cleaner low-carbon fuels. The LCFS is expressed in term of the carbon intensity (CI) of the fuel used and depends on an LCA of this fuel. Fuels below the CI benchmark generate credits, while those above the CI benchmark generate deficits. LCFS programmes are being progressively expanded to Oregon, Washington and the Canadian province of British Columbia. This programme has been designed to be fuel and technology neutral. Any pathway that allows for a reduction of the CI is potentially allowable, including renewable methanol. This avoids the pitfalls of some other programmes, which mandate specific fuels or pathways, such as cellulosic ethanol, whose production on a large scale has failed to materialise.

The European Union has put forward its "Green Deal" roadmap, aiming to become carbon neutral by 2050 (EU, 2020a). This implies that in 30 years' time all transport fuels should be 100% renewable. At the same time the only currently acknowledged pathway is a system based on quotas that are put in place for low concentrations (low blends) of renewable fuels blended into crude oil refineries. Today's refineries can only blend low percentages of oxygen-containing renewable fuel intermediates into their processes for both process and construction material reasons. The current situation for pure renewable fuels is thus weak, with a lack of support mechanisms in most markets. Consequently, quotas for 100% renewable fuels should also be introduced. A necessary change in this respect is needed regardless of which GHG-neutral fuel system one sees as the strongest candidate, or rather candidates, to reach the goal of a fully renewable transport sector.

In terms of CO_2 emission regulations, a cap-and-trade system, the EU Emissions Trading System, for the trading of carbon emission credits was introduced in in 2005. Other countries that have also implemented cap-and-trade programmes or carbon taxes include, among others, South Korea, Australia, New Zealand, Japan, Canada, Mexico, Argentina, the Chinese province of Guangdong and the US state of California. Placing a value on carbon is an important step in climate policies to reflect the externalities created by pollution. A value on carbon creates a business case for investment in CCU, increased use of biomass and a progressive move towards a net carbon-neutral society.

Renewable fuels are typically more expensive than fossil fuels, and require higher up-front investment. Even though methanol is one of the most cost-effective renewable fuels to produce, this is also true for this alternative.

Policy instruments providing a long-term guaranteed price floor for renewable methanol (as well as for other promising fuel alternatives) would be beneficial to remove some of the investment risks. A meaningful production support system that could motivate investment is a contract for difference (CFD) scheme in which advanced renewable fuel production projects bid for – and winners are awarded – CFDs in so-called reverse auctions (lowest bid wins). As illustrated in Figure 48, a CFD pays out the difference between an uncertain or insufficient market price and the price required to finance the project (strike price). Auctions are held on a recurring basis according to set categories, each for a different type of route to renewable fuels, with a specific maximum administrative strike price and specific terms. These parameters can change according to policy needs, technology and cost reduction, leaving the government in control – the key feature is that they do not change for a project once offered and awarded, providing the required long-term stability needed for finance.

CFDs are instruments that are well-known by capital markets and which have been very successful, for example, in developing and securing finance for offshore and onshore wind in the United Kingdom and in Denmark (UK GOV, 2020).

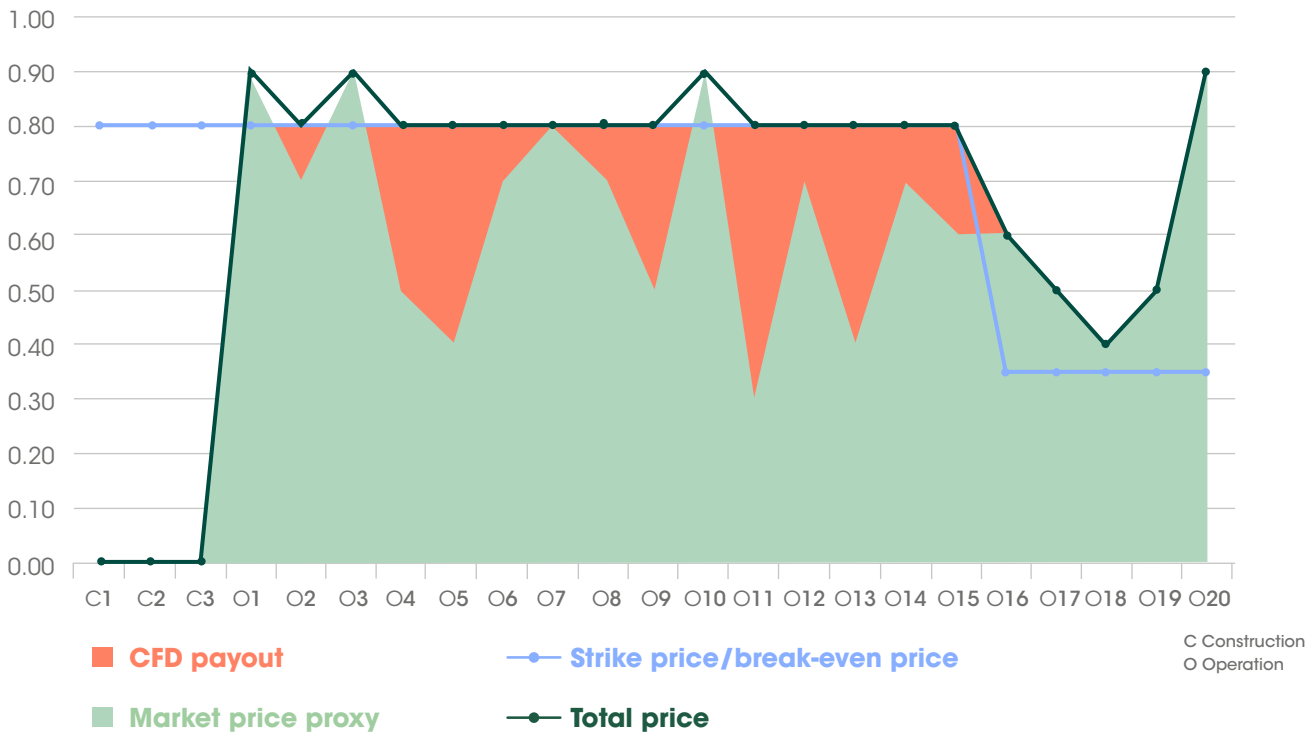
As part of the "EU Green Deal implementation" it has been proposed to introduce a "carbon CFD" pilot scheme, similar to tendering systems for renewable power, which could pay the difference between a CO_2 strike price and the actual CO_2 price in the EU ETS to bridge the cost gap between conventional and decarbonised hydrogen (EU, 2020b). Applied at an EU or national level, an appropriate state aid framework could be developed (2021 revised state aid guidelines for energy and environmental protection). This indicates that it should be possible to expand the CFD mechanism, which was so successful in helping to bring down the cost of wind power, to support the commercial introduction of renewable methanol.

Policy experience has shown that picking winners at the onset is not usually the best approach. To obtain the best results, it seems that policies should be technology and fuel agnostic and focus on the actual outcome, e.g. lower pollutant emissions including CO_2, sustainability, and increased energy security though local production. For this, LCAs and other benchmarks will be needed to weight the benefit of each process and fuel.

In the transition to fully renewable methanol production, the co-production of green and conventional products with proportionate credit should also be allowed. These include LCM technologies where green hydrogen is added in the process of methanol production from natural gas. This would allow for a progressive greening of the methanol produced while keeping costs low. Once the technologies (electrolyser) are scaled up and the cost of renewable power low enough, the share of green methanol, and credits, could increase.

Policies and tax incentives on fuel should be based on energy content, not volume (e.g. USD per kWh, not USD per litre); otherwise, the incentives would penalise some renewable fuels that have lower energy density.

Figure 48. A hypothetical CFD smoothing returns in a volatile market



Source : *Max Jönsson*

In 1997, the US Congress adopted the Taxpayer Relief Act, which set the federal excise tax paid for alternative fuels at the pump on a British thermal unit equivalency with gasoline. For methanol, the federal excise tax was reduced to USD 0.0915 per gallon compared with the excise tax for gasoline of USD 0.184 per gallon. In 2013, in Australia, methanol was granted excise tax-free status (~38 AU¢/litre) for 10 years to encourage its use as a fuel. Energy tax reductions based on energy content can be provided for renewable fuels including methanol fuels, both bio-methanol and e-methanol. Taxation policy can "make or break" alternative fuels.

Policies could also include eco-labelling of bio-and e-based chemicals and products, information campaigns and subsidies for producers of materials that would be progressively phased out as technology matures and production costs decrease.

Transitioning the global economy to carbon-neutral energy will take massive investment in technology development, infrastructure and deployment. Economies of scale for renewable methanol production and use will lead to competitive fuel pricing for multiple sectors. As a liquid with the highest hydrogen-to-carbon ratio of any liquid fuel, methanol can be a key energy carrier. Since methanol can be utilised in existing combustion engines, as well as more advanced powertrains and chemical production processes, conventional grey and blue methanol can be used today, with greater substitution of green methanol over time. Renewable methanol is uniquely positioned to be a future-proof fuel.

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ANNEXES

Annex 1. Some of the pros and cons of methanol and renewable methanol

PRODUCTION AND CHEMICAL APPLICATIONS

Pros	Cons
+ Commonly produced on an industrial scale with high yields and efficiency from various carbon-containing feedstock. Natural gas and coal today; biomass, solid waste and CO_2 + H_2 tomorrow.	× Production from coal has a large carbon footprint.
+ Already used to produce hundreds of everyday industrial chemicals and products as well as consumer items.	× Production of renewable methanol remains more expensive than fossil methanol.
+ Could be used for the production of aromatic compounds (BTX) and other chemicals currently obtained from petroleum.	× Production of renewable methanol needs to be scaled up.
+ No inherent technical challenges in scaling up the production of methanol to meet the needs of the transport or chemical industry sectors.	× Competition for renewable feedstock (biomass, CO_2, renewable power) with other renewable alternatives.

PROPERTIES, TRANSPORT AND STORAGE

Pros	Cons
+ Methanol is a liquid. This makes it easy to store, transport and distribute by ship, pipeline, truck and rail.	× Can be corrosive to some metals such as aluminium, copper, zinc, titanium and some of their alloys. Methanol may also attack some plastics, resins and rubbers. Compatible metals, plastics and elastomer materials have to be selected.
+ Requirements for methanol storage and transport are similar to other flammable liquids such as gasoline, jet fuel, and ethanol.	× Methanol can absorb moisture from the atmosphere. To prevent this, methanol should be stored in a sealed container
+ Methanol used as an automotive fuel can be dispensed in regular filling stations, requiring	

only minimal and relatively inexpensive modifications. + Bunkering of methanol for marine applications is similar to marine fuels such as heavy fuel oil. Only minor modifications to existing infrastructure are needed at a modest cost. + When properly stored methanol is stable and its shelf life is indefinite.	where there should be an allowance for thermal expansion (larger tank, floating roof tank, pressure relief valve). Moisture absorbed by neat methanol is fully miscible, and is retained as a single phase that does not affect combustion. Moisture absorbed by gasoline-methanol blends, however, can form immiscible phases. If the amount of water is small it has little effect on combustion, but larger amounts of water phase material can interfere with combustion.

USE AS A FUEL

Pros	Cons
+ Growing market for methanol use as a fuel. Currently about 31% of methanol demand.	× Competition with established fuels (gasoline, diesel) as well as alternatives including electrification, hydrogen, biofuels, CNG, LPG, etc. × Relatively low volumetric energy content compared to some fuels. About half the volumetric energy density of gasoline and diesel fuel.

AS A GASOLINE ADDITIVE AND SUBSTITUTE

Pros	Cons
• High octane rating (RON of 109) and high knocking resistance. Allows the engine to run at high compression ratios for higher efficiency • Can be blended with gasoline in various ratios from 3% to pure methanol (e.g. M3, M15, M85, M100). Concentrations up to 15% (M15) can be used in regular gasoline cars. Higher concentrations (e.g. M85) can be used in flex-fuel vehicles (similar to E85).	× Methanol has low vapour pressure at low temperatures. Cold start system or higher vapour pressure additives might be needed × Poor lubrication properties. × For optimum efficiency at higher concentrations of methanol, engines might need some modifications.

+ High oxygen content (avoids fuel-rich combustion zones). + High heat of evaporation. + Low lean flammability limit. + High volatility. + Compatible with hybrid (fuel/electric) systems and vehicles. + Methanol-to-gasoline (MTG) offers another derivative route, and can be used in existing engines.	

AS A DIESEL SUBSTITUTE

Pros	Cons
+ Methanol can be used in combustion ignition (diesel) engines. + Dimethyl ether derived from methanol is a substitute for diesel fuel (high cetane number). Methanol is also a main component of biodiesel (biodiesel is obtained by transesterification of plant oil and animal fats with an alcohol). Oxymethylene ethers (OME) derived from methanol are also being tested as diesel substitutes. + Trucks with modified engines running on methanol and DME are available or under development.	× Neat methanol in itself is a poor diesel substitute (very low cetane number). To be used in diesel-type engines it needs glow plugs, additives or co-injection of small quantities of diesel (~5%) to ignite when compressed.

AS A MARINE FUEL

Pros	Cons
+ Use of methanol as a marine fuel fulfils the more stringent emission standards in Emission Control Areas (ECAs) and new global emission standard set by the IMO that took effect in 2020 (0.5% sulphur content in marine fuel starting in 2020, compared to 3.5% before). Renewable methanol can also provide pathways to meet the IMO's GHG emission reduction ambitions. + Bunkering of methanol already widely available in many ports around the world. + There are currently more than 20 large ships in operation and on order operating on methanol (DNV GL, 2020). Powered by diesel engines modified to run on both methanol and diesel. Methanol-optimised engines in development are expected to perform even better	× Competing technologies (e.g. selective catalytic reduction, scrubber, filter, exhaust recirculation systems). × Competing fuels (e.g. low-sulphur fuel oil, low-sulphur distillate fuels, LNG, hydrogen, ammonia).

OTHER FUEL USES

Pros	Cons
+ Can be used in a direct methanol fuel cell (DMFC) to produce electricity. + Good liquid hydrogen carrier (one litre of methanol contains more hydrogen than a litre of liquid hydrogen). Methanol is easily reformed to hydrogen for use in fuel cells (reformed methanol fuel cells). + Fuel in methanol-fired turbine engines. + Fuel for cookstoves, industrial boilers, kilns and home heating.	× DMFCs remain costly and capacity-limited. × Methanol reforming to hydrogen should be further improved (e.g. minimise carbon monoxide concentration in reformer outlet to avoid additional treatment).

FUEL AND VEHICLE STANDARDS

Pros	Cons
+ Some fuel and vehicle standards already in place: **United States:** ASTM D4814 (M2.7) **Europe:** EN 228 :2012+A1 :2017(M3) **Israel:** SI 90 parts 2 and 4 (M3-M15) **India:** IS 17076:2019 (M15) **United States:** ASTM D5797-18 (M51-M85) **China:** GB/T 23510-2009 (M100) **China:** GB/T 23799-2009 (M85) **China:** Provincial standards	× Methanol fuel standards need to be expanded to allow for wider use in more countries and for more applications.

POLLUTANT EMISSIONS

Pros	Cons
+ Lower pollutant emissions when combusted: + No carbon-carbon bonds allow for soot-free combustion (no PM). + No SOx. + Lower NOx. + Low-carbon and renewable methanol can provide reduced overall CO2 emissions compared to fossil fuels.	× Incomplete combustion can lead to formaldehyde and formic acid pollutants.

Note: *More details can be found, for example, in MI (2020c); DNV GL (2016); Schröder (2020); and SGS (2020).*

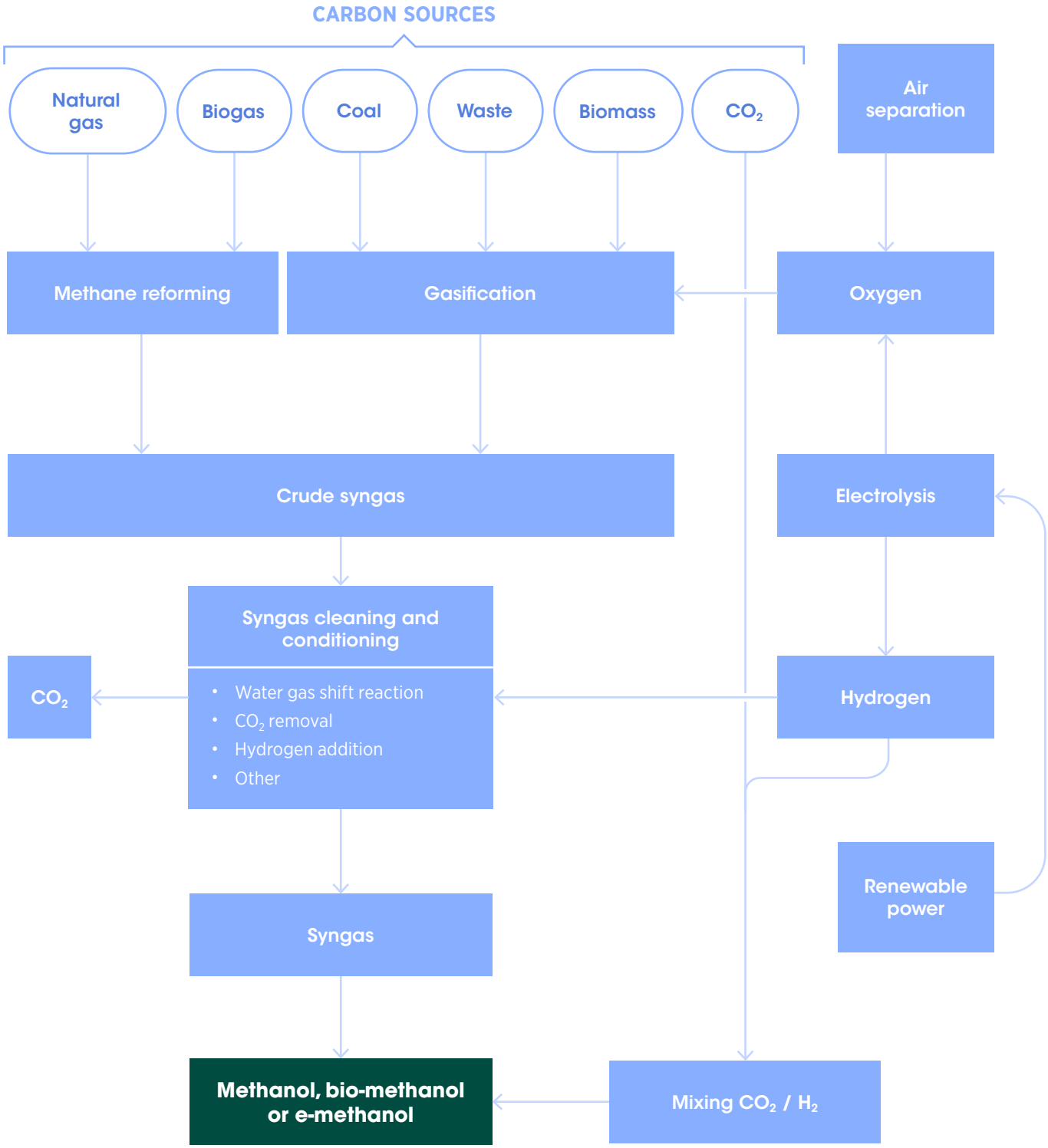
HEALTH AND SAFETY

Pros	Cons
+ Safer fuel in fires than gasoline. Methanol generates less heat and transfers less of the heat to the surroundings. Methanol fires can be extinguished with water or alcohol-resistant foams. + Methanol in small concentrations is present naturally in the human body and food and drinks such as fruits, vegetables, beer, wine, etc.	× Highly flammable. Burns with a low-temperature non-luminous clear blue flame that might be difficult to see in bright light. Combustion is also smokeless. × Can form explosive mixture in air. × Toxic. Toxic exposure can occur by inhalation, skin and eye contact and ingestion. Ingestion of more than 20 mL can be lethal; lesser amounts are known to cause irreversible blindness. Metabolism and toxicity of methanol are similar to those of ethylene glycol. The degradation products of methanol, formaldehyde and formate are responsible for its toxicity. Adequate precautions should be taken while handling and dispensing.

ENVIRONMENT

Pros	Cons
+ Methanol is water soluble and readily biodegradable. Methanol dissolves completely in water. When released into water, it will rapidly disperse to low concentrations, allowing micro-organisms occurring naturally to degrade it in a relatively short time. + Methanol is used in water treatment plants for denitrification. Methanol is an energy source for the organisms breaking down the nitrogen-containing compounds present in wastewater + Methanol is a naturally occurring substance which does not bio-accumulate. + Non-environmentally hazardous according to the dangerous goods regulations.	× Spillage to the environment. When released into soil, methanol could enter groundwater. However, because methanol is readily biodegradable its accumulation in soil or groundwater is unlikely.

Annex 2. Overview of major methanol production processes from various carbon sources.



Annex 3. Comparison of renewable methanol with other fuels on a price per unit of energy basis

Fuel type		Price (USD/GJ)	Price (EUR/GJ)	Source
Fossil methanol		10.1-20.1	9.0-18.1	This report
Bio-methanol (current)	< USD 6/GJ feedstock cost	16.4-38.4	14.8-34.6	This report
	USD 6-15/GJ feedstock cost	22.9-50.9	20.6-45.8	This report
Bio-methanol (mature process 2030-2050) cost	< USD 6/GJ feedstock cost	11.4-27.8	10.3-25.0	This report
	USD 6-15/GJ feedstock cost	17.8-42.4	16.1-38.2	This report
E-methanol (current) cost	From combined renewable source	41.2-81.4	37.1-73.3	This report
	From DAC only	67.8-119.6	61.1-107.6	This report
E-methanol (mature process 2030-2050) cost	From combined renewable source	12.6-31.7	11.3-28.5	This report
	From DAC only	14.5-31.7	13.0-28.5	This report
Gasoline (US Gulf Coast) before tax		16.9	15.2	EIA
Diesel (US Gulf Coast) before tax		16.0	14.4	EIA
Heating Oil No. 2 (New York Harbor), before tax		15.8	14.3	EIA
Jet fuel (US Gulf Coast), before tax		16.1	14.5	EIA
Petroleum oil (US, WTI)		11.7	10.5	EIA
Petroleum oil (Europe, Brent)		12.7	11.5	EIA
Gasoline (retail, average US, with tax)		23.4	21.0	AFDC
Diesel (retail, average US, with tax)		23.4	21.1	AFDC
LNG (retail, average US, with tax)		20.8	18.7	AFDC
CNG (retail, average US, with tax)		17.1	15.4	AFDC
Gasoline (retail, average EU, with tax)		48.9	44.0	EEA
Diesel (retail, average EU, with tax)		44.3	39.9	EEA

Notes: Values calculated according to the LHV of the fuel. Conversion factor used USD 1 = EUR 0.9. Average of prices over the past 10 years.

Sources: EIA (US Energy Information Administration), *https://www.eia.gov*; AFDC (Alternative Fuels Data Center), US DOE, *https://afdc.energy.gov/fuels/prices.html*; EEA (European Environment Agency), *https://www.eea.europa.eu/data-and-maps/indicators/fuel-prices-and-taxes.*

Annex 4. Overview of existing or planned facilities and technology providers for e-methanol and bio-methanol production

PLANTS (EXISTING AND PROJECTED)					
E-METHANOL					
Country	**Company**	**Start-up year**	**Capacity (t/y)**	**Feedstock**	**Source**
Iceland	Carbon Recycling International (CRI)	2011	4 000	Geothermal CO_2 and H_2 from water electrolysis	CRI, 2020 Product sold under the name "Vulcanol"
China	Dalian Institute of Chemical Physics	2020	1 000	CO_2 and H_2 from water electrolysis (PV)	AAAS, 2020
Sweden	Liquid Wind	2023 (plan for 6 facilities by 2030)	45 000	Upcycled industrial CO_2 and H_2 from water electrolysis	Liquid Wind, 2020
Australia (Tasmania)	ABEL	2023	60 000	Biogenic CO_2 and H_2 from water electrolysis	ABEL Energy, 2020
China	Henan Shuncheng Group / CRI	2022	110 000	CO_2 from limekiln and H_2 from coke oven gas	CRI, 2020
Norway	Swiss Liquid Future / Thyssenkrupp	n/k	80 000	CO_2 from ferrosilicon plant and H_2 from water electrolysis (hydro)	Swiss Liquid Future, 2020a, Swiss Liquid Future, 2020b
Norway	Joint Venture/CRI	2024	100 000	CO_2 and H_2 from water electrolysis	Stefánsson, 2019
Canada	Renewable Hydrogen Canada (RH_2C)	n/k	120 000	CO_2 and H_2 from water electrolysis (hydro)	RH_2C, 2020
Belgium	Consortium at the port of Antwerp	n/k	8 000	CO_2 and H_2 from water electrolysis	INOVYN, 2020
Belgium	Consortium at the port of Ghent	n/k	46 000-180 000	Industrial CO_2 and H_2 from water electrolysis	aet, 2019
The Netherlands	Consortium Nouryon/Gasunie/ BioMCN/3 others	n/k	15 000	CO_2 and H_2 from water electrolysis	Nouryon, 2020
Germany	Dow	n/k	~ 200 000	CO_2 and H_2 from water electrolysis	Schmidt, 2020
Denmark	Consortium of companies	2023-2030	n/k	CO_2 from MSW and biomass. H_2 from water electrolysis (offshore wind). Up to 1.3 GW electrolyser capacity by 2030	Maersk, 2020
Germany	Consortium	n/k	n/k	CO_2 from cement plant and H_2 from water electrolysis (wind)	Westküste 100, 2020

PLANTS (EXISTING AND PROJECTED)					
BIO-METHANOL					
Country	**Company**	**Start-up year**	**Capacity (t/y)**	**Feedstock**	**Source**
United States	LowLand Methanol Consortium of companies	2023	120 000	MSW/waste wood	LowLands Methanol, 2020
Sweden	Södra	Operational	5 250	Extraction from pulping process	Södra
Canada	Alberta Pacific	Operational	3 000	Extraction from pulping process	Alberta Pacific
Sweden	Värmlandsmetanol	Planning	100 000	Biomass	Värmlandsmetanol, 2017
Sweden	Domsjö	Preliminary engineering	147 000	Black liquor	Chemrec
United States	New Hope Energy	2023/24	715 000	Biomass	New Hope Energy
Canada	Enerkem	Operational	30 000 (ethanol*)	MSW	Enerkem
Canada	Enerkem	Under construction	35 000 (ethanol*)	MSW	Enerkem
Netherlands	Enerkem Consortium of companies	Engineering phase	215 000	MSW	Enerkem
Spain	Enerkem	Engineering phase	215 000	MSW	Enerkem
Germany	BASF	Operational	480 000**	Natural gas/ biomethane	BASF
Netherlands	OCI/BioMCN	Operational	60 000***	Natural gas/ biomethane	OCI/BioMCN
United States	OCI Beaumont	Operational	1 075 000 ****	Natural gas/ biomethane	OCI
Sweden	Perstorp	Planning	200 000	Biomethanol/ Green hydrogen	Perstorp, 2020

** Syngas conversion to methanol, which is further converted to ethanol.*

*** Plant capacity: (Saygin and Gielen, forthcoming) bio-methanol share is around 15%.*

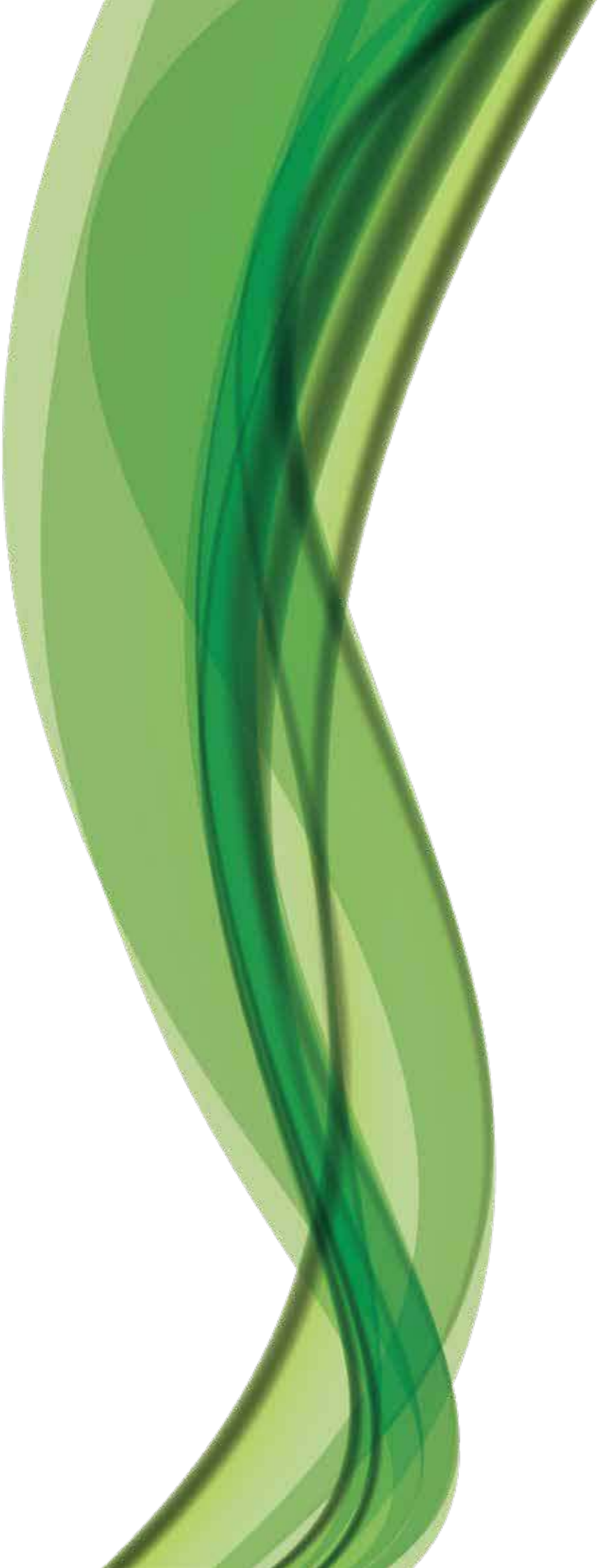
**** Biomethanol part: (Compagne, 2017).*

***** Plant capacity: (OCI, 2020) bio-methanol share not given.*

TECHNOLOGY DEMONSTRATION PLANTS (PAST AND CURRENT)					
E-METHANOL					
Country	**Company**	**Start-up year**	**Capacity (t/y)**	**Feedstock**	**Source**
Sweden	FReSMe	2019	1 t/d	CO_2 and H_2 waste stream from steel manufacturing and H_2 from water electrolysis	FReSMe, 2020
Germany	MefCO_2	2019	1 t/d	Power plant flue gas CO_2 and H_2 from water electrolysis	MefCO_2, 2020
Denmark	Power2Met Danish Consortium	2019	800 L/d	CO_2 from biogas and H_2 from water electrolysis (wind and solar)	REintegrate, 2020
Germany	Carbon2Chem	2020	50 L/d	CO_2/CO/H_2 from steel mill gases and H_2 from water electrolysis	Carbon2Chem, 2020
Germany	ALIGN-CCUS Project DME from CO_2	2020	50 L DME/d	CO_2 from power plant flue gas and H_2 from water electrolysis	ALIGN-CCUS, 2020
Switzerland	Swiss Liquid Future	2012	75 L/d	CO_2 and H_2 from water electrolysis	Swiss Liquid Future, 2020a
Germany	TOTAL / Sunfire e-CO_2Met project	2022	1.5 t/d	CO_2 from a Refinery and H_2 from water electrolysis	TOTAL, 2020
Germany	bse Engineering /Institute for Renewable Energy Systems (IRES)	2020	28 L/d	CO_2 and H_2 from water electrolysis (wind)	bse Engineering, 2020
Japan	Mitsui	2009	100 t/y	CO_2 and H_2 from water electrolysis	Mitsui Chemicals, 2009, 2010
Korea	Korean Institute of Science and Technology (KIST) /CAMERE process	2004	100 kg/d	CO_2 from power plant flue gas and H_2 from water electrolysis	Joo, 2004

TECHNOLOGY DEMONSTRATION PLANTS (PAST AND CURRENT)					
BIO-METHANOL (gasification technologies generating syngas for methanol and other products)					
Country	**Company**	**Start-up year**	**Capacity (t/y)**	**Feedstock**	**Source**
France	BioTfueL Demo Project 2019 (BioTfuel, 2020)	2019	15 MW feedstock	Biomass (torrefied) To FT products	BioTfuel, 2020
Sweden	Chemrec	2005	3 MW feedstock	Black liquor to methanol and DME	BioDME demo plant Chemrec, 2020
Germany	KIT, Karlsruhe Institute of Technology	2013	1 t/hr feedstock	pyrolysis oil from straw to gasoline via DME	KTI demo project KIT, 2020
United States	GTI	2012	19 t/d	Various biomass materials to gasoline, SNG and other	GTI demo plant GTI, 2020
United States	TRI, ThermoChem Recovery International, Inc			Biomass and MSW to FT products	TRI demo project TRI, 2020
Canada	Enerkem	2009	48 dry t/d feedstock	MSW and biomass to methanol and ethanol	Enerkem demo plant Enerkem, 2020

SOME OF THE TECHNOLOGY PROVIDERS					
E-METHANOL					
Country	**Company**	**Start-up year**	**Capacity (t/y)**	**Feedstock**	**Source**
Iceland	Carbon recycling International (CRI)	Technology provider	50 000-100 000	CO_2 and H_2 from water electrolysis	CRI, 2020
Germany	Thyssenkrupp/ Uhde/Swiss Liquid Future	Technology provider	3 600-72 000	CO_2 and H_2 from water electrolysis	Thyssenkrupp, 2020a
Germany	bse Engineering /BASF	Technology provider	8 200-16 400	CO_2 and H_2 from water electrolysis	bse Engineering, 2020
Denmark	Haldor Topsoe	Technology provider	Variable	CO_2 and H_2 from water electrolysis	HT, 2019a
United Kingdom	Johnson Matthey	Technology provider	Variable 100 000-1 700 000	CO_2 and H_2 from water electrolysis	JM, 2020
BIO-METHANOL (GASIFICATION TECHNOLOGIES PRODUCING SYNGAS FOR FURTHER CONVERSION E.G. TO METHANOL)					
Country	**Company**	**Start-up year**	**Capacity (t/y)**	**Feedstock**	**Source**
United States	TRI, ThermoChem Recovery International, Inc	Technology provider	The gasification unit can have multiple parallel trains. One gasifier train varies in size from 20-30 MW to 100-150 MW feedstock.	Various biomasses and MSW	TRI
Germany	KIT, Karlsruhe Institute of Technology	Technology provider		Pyrolysis oil and char from straw	KIT
Sweden	Chemrec	Technology provider		Black liquor and similar	Chemrec
Germany	ThyssenKrupp	Technology provider		Biomass	ThyssenKrupp
Canada	Enerkem	Technology provider		MSW and biomass	Enerkem
United States	GTI/Sungas	Technology provider		Biomass	GTI/Sungas
Italy	NextChem	Technology provider		MSW	NextChem



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