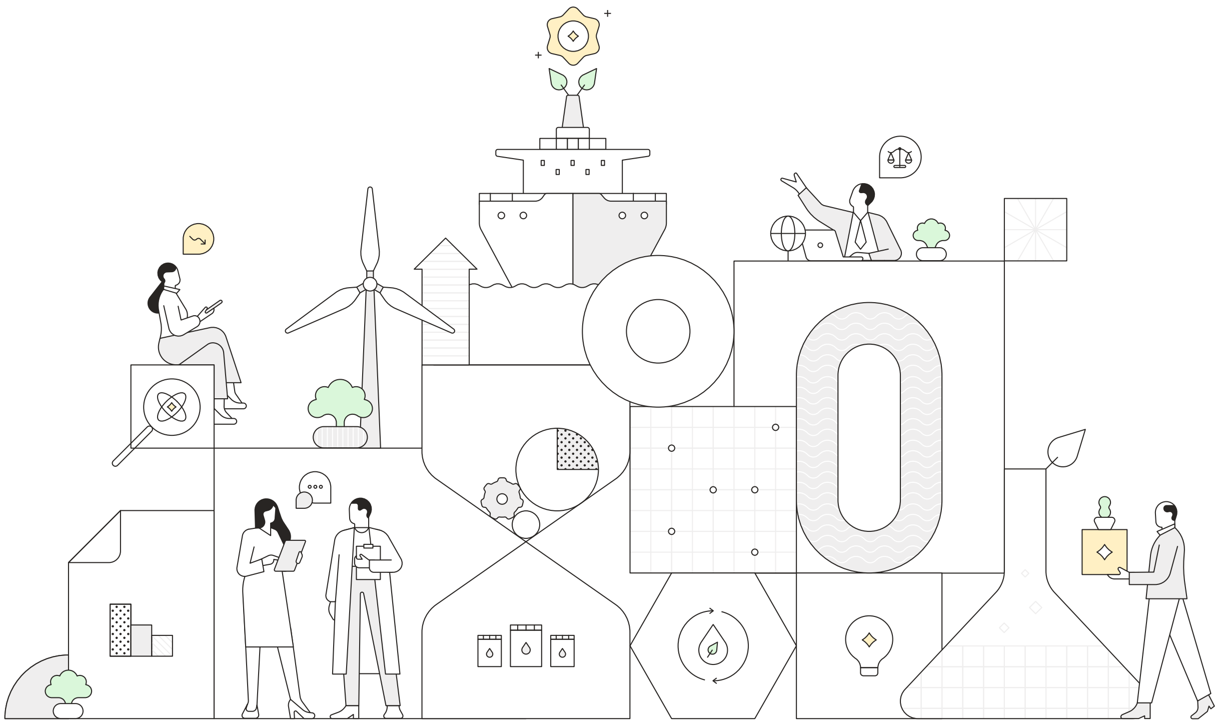
Biogas as a Source of Biofuels for Shipping

Techno-Economic Trends

Mærsk Mc-Kinney Møller Center
for Zero Carbon Shipping

Contents



Executive Summary

Decarbonization of the shipping industry will require access to a range of alternative low- or zero-carbon fuels in the coming years. To this end, this series of reports presents a deep dive into the potential of biogas as a source of biofuels for shipping. Biogas, generated by anaerobic digestion of biomass, is a mixture of methane (CH_4) and carbon dioxide (CO_2) which can be easily transformed into various biofuels. The process of manufacturing marine biofuel from biogas is broadly sketched in Figure 1.

Biomass is one of the main inputs for biofuel production from biogas. Converting biomass into biofuel often requires extensive chemical and physical processing, which consumes energy. In particular, manufacturing processes that use hydrogen consume large amounts of electricity. Energy is also needed for transport and storage throughout the value chain, and it may be lost as unwanted emissions. Overall, biogas-based biofuel manufacturing processes and their supply chains are complex, and the price of raw materials and renewable energy is stretched due to high demand. Thus, it is valuable to understand the cost of biofuel production and its composition in order to reduce the cost 'hotspots'.

Furthermore, the value of a given biofuel as a means to decarbonize shipping rests on its ability to lower greenhouse gas (GHG) emissions with respect to fossil fuels. This ability is called the fuel's decarbonization efficiency. A fuel's decarbonization efficiency is determined by the biofuel's emissions intensity, which is based on the total GHG emissions associated with its manufacture and use. The emissions intensity of a biofuel depends on both its associated conversion efficiency and on specific choices in the value chain, including sustainability of biomass, origin of electrical power, and fugitive emissions.

In this report, we link manufacturing costs to decarbonization performance and compare manufacturing processes and biofuels based on the cost of avoided emissions. The routes to biogas-based biofuels described in this study comprise both fully commercial manufacturing options and alternatives at various stages of commercialization. Technology licensors have provided most of the information we used for our assessment.

We find that biomass price and yield are hotspots that, in the worst case, may cause the cost of biogas production to double. Controlling these factors is therefore essential to control the financial performance of the plant — particularly at large production capacities, which are highly sensitive to feedstock costs.

For biogas manufacture, we find that the economy of scale, which reduces capital expenditure (CapEx) and fixed costs, is opposed by a diseconomy of scale related to biomass and digestate transport. Expanding biogas production capacity by expanding the radius of the area from which biomass is aggregated improves the plant's economics up to a certain capacity. For higher capacities, however, the cost of transport increases disproportionately with respect to savings, and the plant's economic performance declines. Aggregating methane or biogas through pipelines offers an alternative to aggregating biomass. However, there are some trade-offs here too, since laying the pipeline is expensive and the cost is amortized more quickly for larger production capacities. Having access to existing natural gas distribution infrastructure can lower the cost of production significantly. Biofuel production which relies on the use of fossil infrastructure may only be approved as low-carbon fuels if applicable regulations allow mass balancing and the trade of green certificates. The ability to apply green certificate trading and mass balancing is therefore critical to reduce the manufacturing costs of these biofuels.

We considered three different options for biofuel manufacture from biogas:

- Upgrading and liquefaction of biogas
- Catalytic synthetic natural gas (SNG, obtained by converting CO_2 in biogas into more methane by means of hydrogen) manufacture and liquefaction
- bio-methanol manufacture from biogas via hydrogen addition

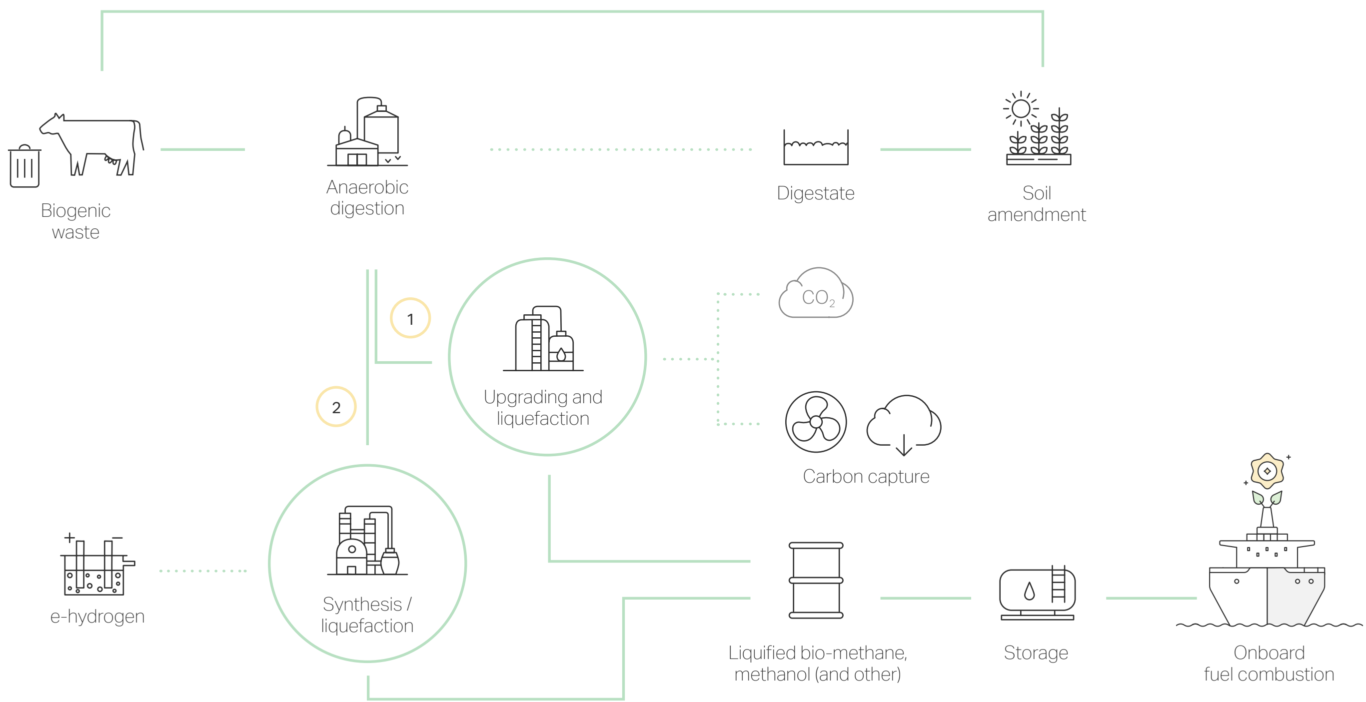
All the biofuel manufacturing options considered in this study have economies of scale, and capacity aggregation is therefore essential to reduce costs.

Electricity is a dominating input for bio-methanol and SNG production. The consumption of electricity in these pathways is largely determined by the electrolyzer's demand and electrolysis efficiency. For the pathways explored in this study, the latter is already very high, with typical solid oxide electrolyzer cells (SOEC) energy conversion efficiency at around 90%. Decreasing electricity demand substantially does not seem likely. Thus, we find that the high consumption of electricity is a disadvantage for the assessed routes for SNG and bio-methanol manufacture.

Overall, we find that the production of liquified bio-methane via the commercially available route outcompetes the hydrogen-supported processes in terms of cost per unit of energy. At a cost of 80–130 EUR/MWh, standard liquified bio-methane production is around 50%–70% cheaper than the alternatives at a comparable capacity.

The standard route to liquified bio-methane becomes particularly attractive if CO_2 can be captured and stored. For supply chains (including the ship sailing on the biofuel) which practise excellence in methane emissions control and sustainable biomass sourcing, the cost of decarbonization for this route per unit tonne of abated CO_2 is in the range of 200 EUR/t, roughly 1/3 that of alternatives depending on how the supply chain is built.

Figure 1: Schematic of a generalized value chain for biofuels from biogas.



1. Introduction

Switching from fossil-based fuels to alternative marine fuels is a key prerequisite for the decarbonization of the shipping industry. Biogas-based biofuels represent an attractive option as part of the alternative fuel mix available to the industry, especially in the shorter term. Biogas is a gas composed mainly of methane (CH_4) and carbon dioxide (CO_2). Biogas is produced by the anaerobic digestion of biomass. Notably, biogas can be used to produce both liquified bio-methane (LBM) — a drop-in replacement fuel for liquified natural gas (LNG) — and bio-methanol, thereby tapping into the industry's growing interest in methanol-fueled vessels. More detailed context on the background, advantages, and challenges surrounding these biogas-based biofuels can be found in our companion publication 'Biogas as a source of biofuels for shipping: insights into the value chain'.

Traditionally, anaerobic digesters were established as sites for the treatment or valorization of waste. As a result, these plants have often operated with small production capacities of a few hundred normal cubic meters (Nm^3) of biogas per hour. A biogas plant producing 850 Nm^3/h could generate around 2,600-2,700 tonnes per year (t/y) of bio-methane, equivalent to 3,200-3,300 t/y of fuel oil. This is enough to satisfy the needs of a small cruise ship or chemical tanker, but not the needs of large container ships and liquified gas tankers which consume 25,000-45,000 t/y of fuel oil. For this reason, biogas has historically attracted little interest from the shipping industry as a potential source of biofuels. Nowadays, however, biogas producers are transforming themselves into energy companies. The biogas industry is pushing technological evolution to support high production capacities for individual plants and to support energy infrastructure that will help aggregate production of small plants.

The objective of this study is to understand how the cost of producing biofuels depends upon the type of biofuel (biogas-based LBM and bio-methanol), production capacity, and integration with energy infrastructure such as biogas or natural gas networks. Our investigations were aimed at uncovering the "hotspots" or the most impactful components of the cost distribution and proposing suggestions to reduce their magnitude.

Keeping in mind that decarbonization is the final objective and that the production and use of biofuels are subject to significant differences in emissions intensity (as determined in our accompanying study on well-to-wake (WTW) greenhouse gas (GHG) emissions), we used the cost of production generated in this exercise to calculate decarbonization costs for various biofuel production pathways.

1.1 About this project

This study forms a part of a broader project established to understand the hurdles that lie in the path to a widespread adoption of biogas-based LBM and bio- methanol fuels in shipping and to offer strategies for resolving these hurdles.

This report is part of a series on "Biogas as a source of biofuels for shipping". Other reports in this series deal with insights into the value chain, methane emissions, energy demand for emission reduction compliance, WTW GHG emissions, and biomass availability.

The project was a collaboration between the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping (MMMCZCS) and our partners Boston Consulting Group, Cargill, Maersk, Norden, Topsoe, and TotalEnergies. A full list of project participants is provided in Section 5.

Our project partners

BOSTON CONSULTING GROUP

Cargill

NORDEN

MAERSK

TOPSOE

TotalEnergies

2. Study scope and methods

Broadly speaking, the process of manufacturing marine fuels from biogas begins with feeding biomass into an anaerobic digester. The digester produces biogas, which is a mixture of methane and CO_2. Once biogas is produced, there are several possibilities for next steps. One option is to further process the biogas and remove the CO_2 through a procedure called upgrading. This results in a pure methane stream which can then be liquified. In this method, CO_2 is released into the atmosphere.

Another option is to have biogas react with hydrogen to convert the CO_2 in the biogas into more methane, thereby creating synthetic natural gas (SNG).

A third option is to directly use biogas to manufacture bio-methanol. This is not the only way to produce bio-methanol from biogas[1]. It is also possible to produce bio-methanol from biogas by taking the CO_2 discarded in the methane upgrading process (mentioned above) and making it react with hydrogen. Alternatively, bio-methanol can be produced from biogas by using methane from a natural gas grid that also transports bio-methane and acquiring the "bio" credentials via mass balancing and purchase of green certificates. Finally, bio-methanol may be produced by processing biomass through gasification instead of anaerobic digestion, which is an entirely different process.

This study concerns specific manufacturing routes and cannot be generalized to encompass bio-methanol manufacturing in a broader sense.

Our companion reports on energy demand for emissions reduction compliance and WTW GHG emissions describe in detail the routes to produce bio-methanol and LBM from biomass via anaerobic digestion, the associated energy and material flows, and the emissions intensities of the resulting biofuels. Here, we combine those results with information on capital investments and operating costs to assess the production costs of these marine biofuels.

2.1 Routes

Figure 2 and Figure 3 summarize selected routes to LBM and bio-methanol that form the focus of this report. The routes are envisaged to provide aggregation options and to study the economic advantage associated with building production facilities of large capacity (economy of scale).

For LBM, we considered four production routes summarized in Figure 2:

- Route 1: a decentralized bio-methane plant consisting of a decentralized anaerobic digester that produces biogas and an upgrading facility that separates CO_2 from bio-methane. The plant also comprises polishing and liquefaction of bio-methane.
- Route 2: multiple bio-methane plants delivering bio-methane to either a local network or the natural gas grid. A centralized polishing and liquefaction plant is fed with bio-methane from the network.
- Route 3: a decentralized anaerobic digester delivering biogas to decentralized manufacturing of SNG with annexed liquefaction facility.
- Route 4: multiple anaerobic digesters delivering biogas to a biogas network, which feeds a centralized facility. The facility may carry out either biogas upgrading to bio-methane or SNG production, along with bio-methane/SNG liquefaction. The need for polishing depends on the bio-methane's purity.

We also considered two production routes for bio-methanol from biogas (Figure 3):

- Route 5: a decentralized anaerobic digester delivering biogas to decentralized manufacturing of bio-methanol.
- Route 6: multiple anaerobic digesters deliver biogas to a biogas network, and a centralized facility for bio-methanol manufacturing is fed with biogas from the network.

Further details on the assumptions behind aggregation models can be found in our companion reports on energy demand for emissions reduction compliance and WTW GHG emissions.

Figure 2: Routes to LBM production and bunkering via centralized and decentralized plants.
NG = natural gas, SNG = synthetic natural gas.

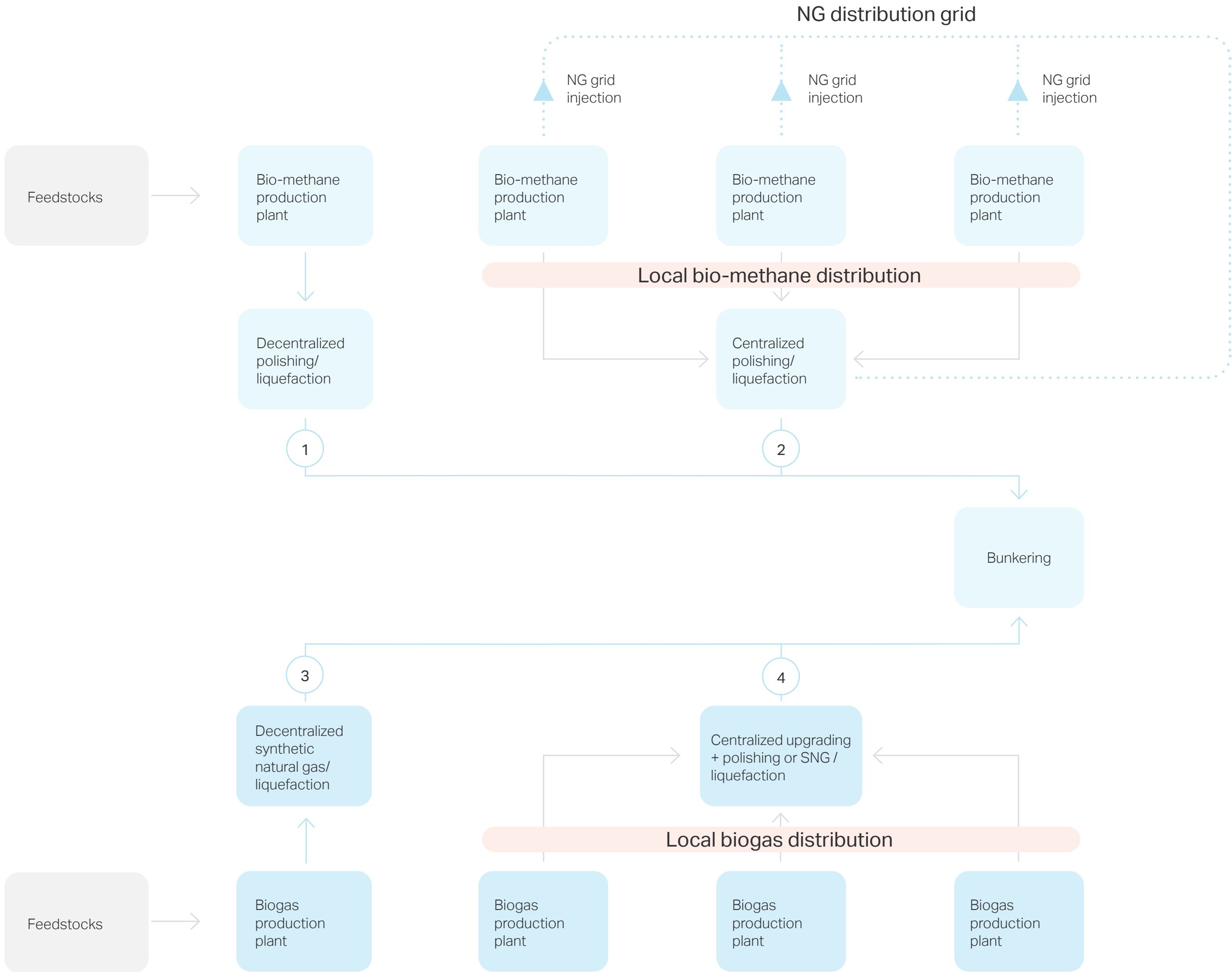
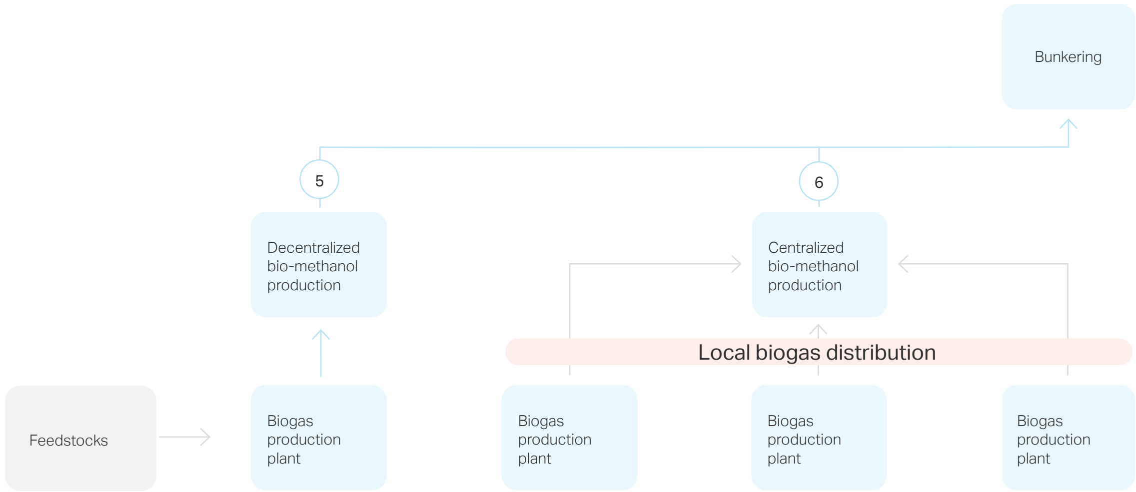
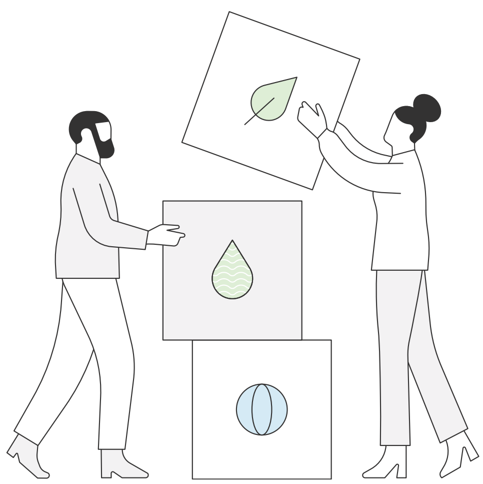


Figure 3: Routes to bio-methanol production and bunkering via centralized and decentralized plants.



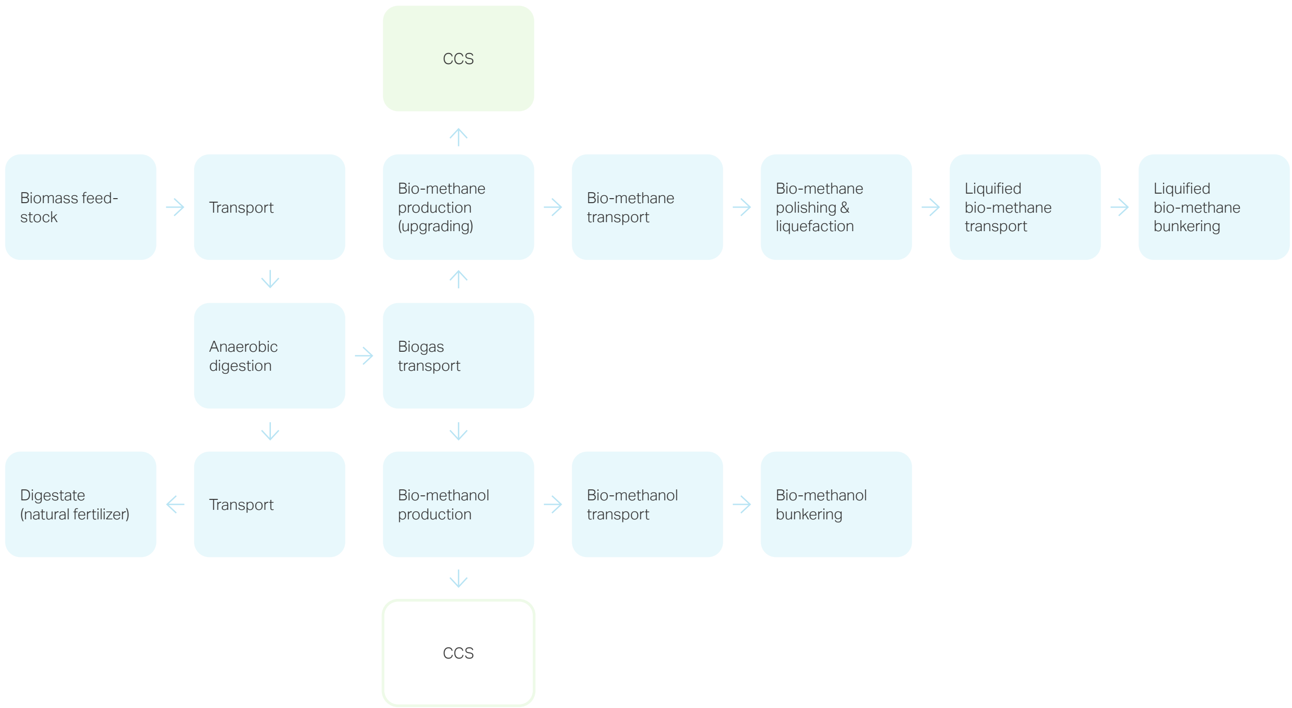


2.2 Cost components

The cost structure of LBM and bio-methanol as shipping fuels depends on the different transformation and transport steps in the supply chain. Figure 4 outlines the cost components considered in this report.

Not all cost components are used for all routes considered in this study. Notably, carbon capture and storage (CCS) may be applied to some configurations of the bio-methanol production process (see our report on energy demand for emission reduction compliance and,[1]) but it has not been included in our techno-economic assessment.

Figure 4: Summary of cost components of LBM and bio-methanol. CCS = carbon capture and storage.



2.3 The reference biogas plant

Our techno-economic model used the French bio-methane plant Biovilleneuvois (BioV) as a starting point.[2] BioV has a biogas production capacity of 850 Nm^3/h, of which 520 Nm^3/h is bio-methane and almost all the rest is CO_2. The plant is fed with mixed biomass collected from an area within an average distance of 15 km from the plant. BioV comprises a biomass delivery and pretreatment section, anaerobic digesters with in-situ biogas desulfurization using iron chloride, and biogas upgrading into bio-methane by means of membrane separation. CO_2 is rejected to the atmosphere while bio-methane is compressed to 40 bar, odorized, and injected into the natural gas grid. Digestate, the main byproduct, is a natural fertilizer that is transported and spread onto the surrounding agricultural fields at an average distance of 17 km from the plant. BioV is further described in our companion report on energy demand for emission reduction compliance.

2.4 Techno-economic model

For our techno-economic analysis, the production costs of bio-methanol or bio-methane from biogas are divided into the following components:

- Feedstock supply
- Feedstock transport
- Digestate transport and spreading
- Investment (capital expenditures or CapEx) comprising engineering, procurement, construction, land, permits, etc.
- Fixed costs for maintenance and operation, insurance, and local taxes
- Variable costs for consumables (operational expenses or OpEx) comprising utilities, consumables, catalysts, etc.

Table 1 summarizes our data sources, method, and some critical assumptions. Information on CapEx and OpEx was in part provided by technology suppliers; due to confidentiality restrictions, we may not provide details.

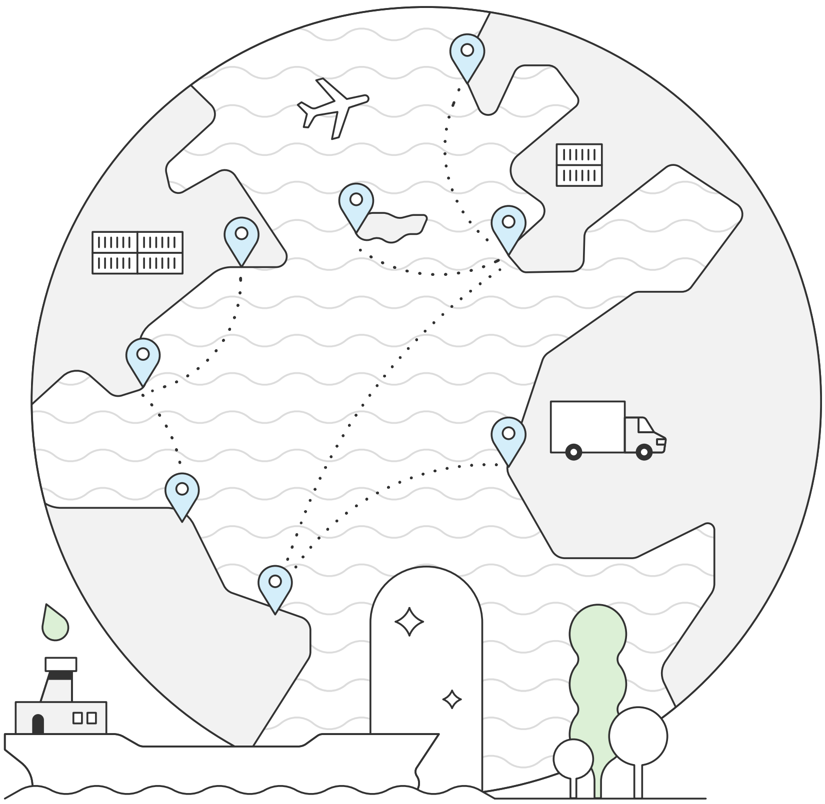


Table 1: Data sources, method, and assumptions for techno-economic analysis.

Data sources	
Feedstock price and physical characteristics	Various sources, see Section 3.1
Feedstock and digestate transport	Scaled from BioV
Biogas production (CapEx, OpEx)	Scaled from BioV using the conventional "0.6 rule"[3]
Upgrading with membrane, compression, and grid injection (CapEx, OpEx)	Scaled from BioV. Scale-up with the conventional "0.6 rule".[3] As CapEx and OpEx data do not distinguish upgrading from compression and grid injection, we have assumed a 50% split
Biomass aggregation	Developed at MMMCZCS
Pipelines for transport	Developed at MMMCZCS based on public data
Hydrogen manufacture via MEP	Developed at MMMCZCS based on public data
Upgrading with amine scrubbing (CapEx, OpEx)	Licensor data at various capacities
Liquefaction (CapEx, OpEx)	Licensor data at various capacities
Methanol manufacture	Licensor data at various capacities
Manufacture of synthetic natural gas (SNG), catalytic route	Licensor data at various capacities
Manufacture of synthetic natural gas (SNG), biological route	Licensor data at various capacities
CO_2 compression for storage (CCS)	If CO_2 is captured, compression and storage amount to ~50 EUR per tonne of stored CO_2
Method	
Variation Min-Max production costs	Min-Max feedstock cost
Combination of different processing units	Carried out at MMMCZCS with the production cost of one unit used as feedstock price for the following
Assumptions	
Plant availability	90% for biogas, 95% for all others
Plant design life	20 years
Discount rate	7%
Biomass price	7.1 EUR/tonne (as received, wet material)
Biomass transport cost (15 km distance)	6.9 EUR/tonne (as received, wet material)
Water price	2.3 EUR/m^3
Electricity price	55 EUR/MWh
Natural gas price	22 EUR/MWh
Revenue from recoverable heat	36 EUR/MWh
CO_2 emissions tax	None

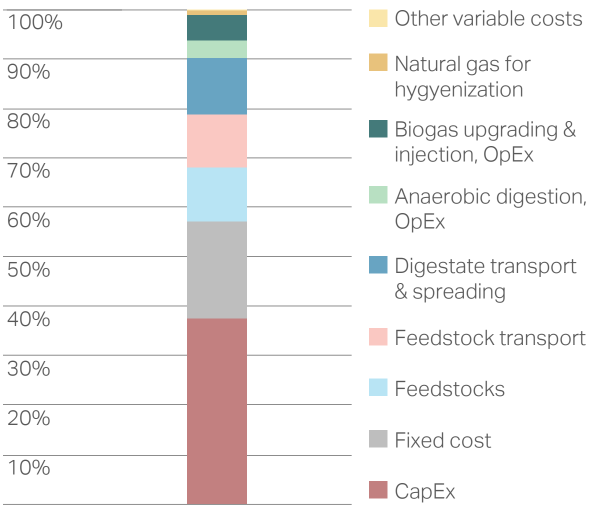
Based on these data, we modeled how different steps in select biofuel production pathways contribute to the production costs in different situations. Our techno-economic models are simplified and combine data from various geographies and time frames. Therefore, we emphasize that the importance of this analysis is in outlining trends and potential cost hotspots rather than in the specific values.

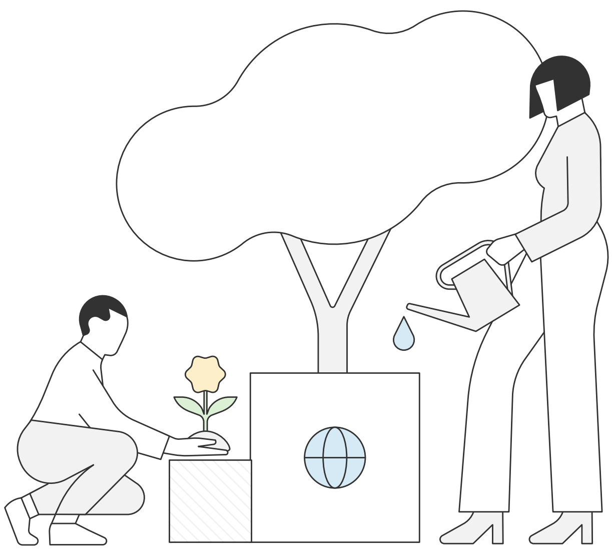
3. Results

3.1 Distribution of production costs in a reference biogas plant

The distribution of production costs for our reference biogas plant, BioV, is shown in Figure 5. Notably, CapEx alone represents 38% of the total cost of production. Fixed costs are related to CapEx, and together these two components account for 58% of the total production cost. As this is clearly a hotspot, one major focus of our subsequent analysis was whether increasing production capacity can reduce the impact of CapEx and fixed costs (see Section 3.3). Other cost hotspots include feedstocks (10% of total production cost) and transport of both feedstocks and digestate (collectively 22%). The contribution of transport costs to the total cost of production also depends upon the production capacity, as we will show later. The remaining approximately 10% of the production cost is due to OpEx, mostly related to anaerobic digestion and biogas upgrading and injection. Due to the low impact of these latter costs, we have not attempted an optimization.

Figure 5: Production costs distribution for the BioV plant, which has a nominal bio-methane production capacity of 500 Nm³/hour. The plant's feedstock plan comprises manure, food wastes, and agriculture residues. Biogas is upgraded via a membrane, pressurized to 40 bar, and injected into the natural gas grid.





3.2 Impact of feedstocks on cost of production

Properties of the chosen feedstocks can impact the cost of biogas and bio-methane produced by anaerobic digestion in numerous ways. For this study, we considered the following feedstocks: crops, agricultural residues, straw, residues from the food industry, livestock manure, and industrial residues. Using data from publicly available sources,[4,5,6,7] we established a simple model that comprises:

- Effect of feedstock price on a plant's operating costs
- Effect of methane yield on feedstock requirement (and resulting impact on bio-methane production and cost of feedstock and digestate transport)
- Effect of feedstock type on cost of transport

Figure 6 shows the consolidated price ranges for various feedstocks. These ranges tend to be very broad due to seasonal and regional characteristics.

Methane yield is the amount of bio-methane that is produced per tonne of feedstock during anaerobic digestion. This yield depends on feedstock type and the dry matter and residual solid content of the fresh feedstocks. Differences in methane yield directly impact the amount of fresh feedstock to be purchased and transported to the anaerobic digestion plants. Figure 7 shows a selection of methane yield data from the literature.[5,6,7,8,9]

Figure 6: Price of selected feedstocks on an as-received basis.

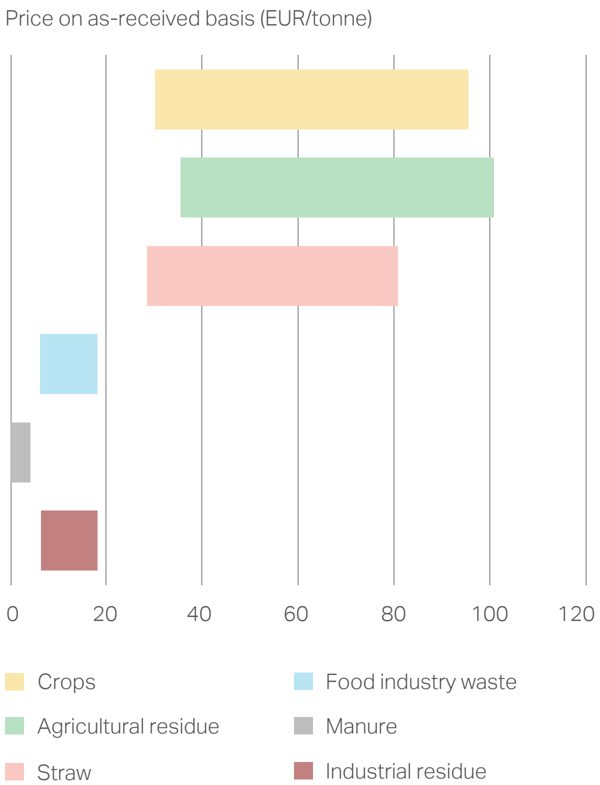
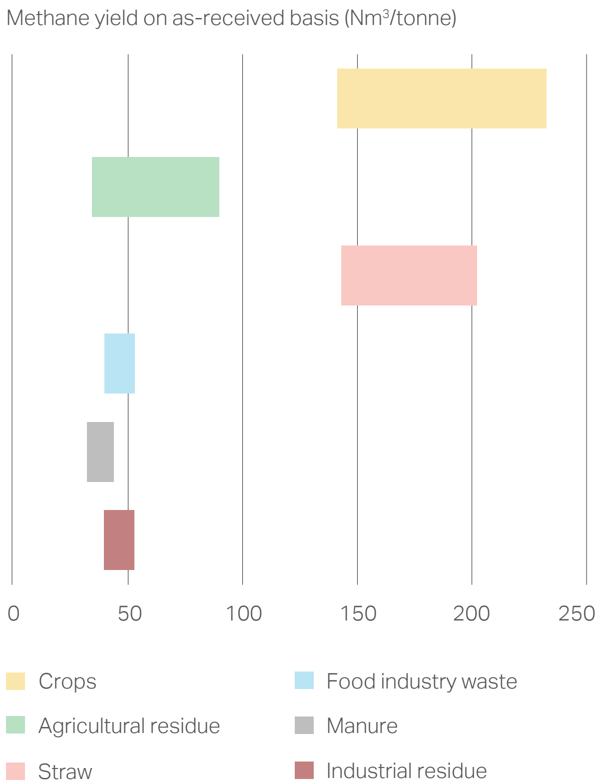


Figure 7: Methane yield for different biomass feedstocks in anaerobic digestion process, on an as-received basis.



Feedstock supply and transport costs have an important impact on the production cost of bio-methane from anaerobic digestion. Figure 8 summarizes these feedstock-related costs for a plant with a bio-methane production of 500 Nm³/h supplied with biomass sourced from an average distance of 15 km.

Feedstocks also vary in characteristics such as dry matter content and density, which influence bio-methane production costs. For example, livestock manure has low methane yield potential, low dry matter content, and high density. Altogether, this results in high logistic costs for manure compared to, for example, straw, which combines high methane yield and high dry matter content. However, the low supply cost of manure makes this feedstock an advantageous source of biomass to produce biogas and bio-methane.

Figure 9 shows the impact of feedstock type on the total cost of production of bio-methane. To generate this figure, we assumed that the anaerobic digester is fed with only one type of feedstock. Comparing the cheapest production costs of manure (approximately 90 EUR/MWh) and the most expensive agricultural residues (approximately 190 EUR/MWh), the figure highlights that variation in feedstock price can change the total cost of bio-methane production by a factor of two depending on the feedstock(s) selected. This finding illustrates that controlling feedstock prices is crucial for the financial performance of a biogas plant.

For the rest of this study, we assumed that the anaerobic digester is fed with a feedstock mix comprising manure, food waste, and agricultural residues, as in BioV (further detailed in our energy demand for emissions reduction compliance study) at an average biomass price as in Table 1.

Figure 8: Impact of feedstock supply and transport on the cost of production of bio-methane. Results based on a bio-methane production capacity of 500 Nm³/hour and feedstock transport distance of 15 km.

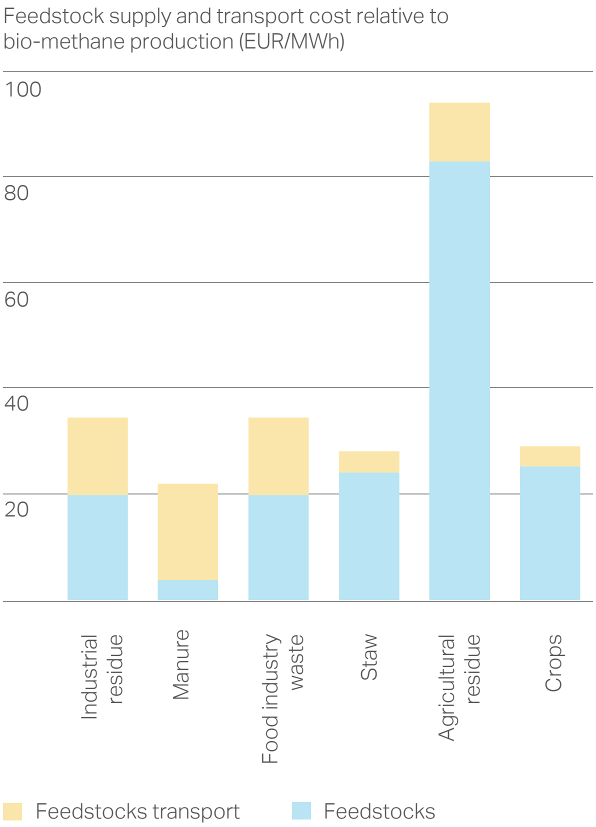
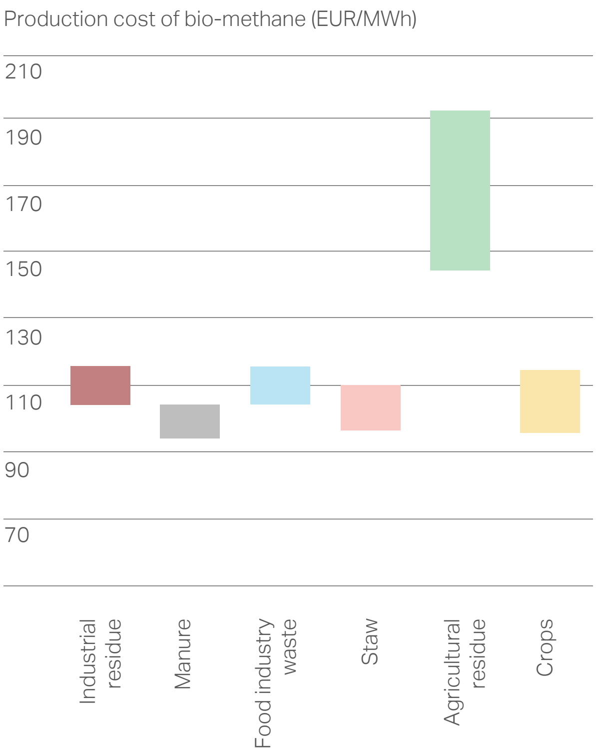


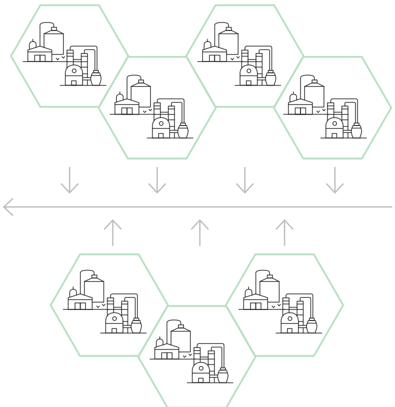
Figure 9: Bio-methane production cost for different fresh feedstocks. Results based on a bio-methane production capacity of 500 Nm³/hour and feedstock transport distance of 15 km.



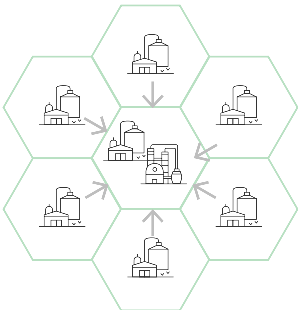
3.3 Scale-up of biogas and bio-methane production

As anticipated in earlier sections, some of the important components of the cost of biofuel production are sensitive to the scale of production. In our energy demand for emissions reduction compliance study, we showed that there are various methods to increase production capacity. For convenience, the scale-up models are shown again in Figure 10. This portion of the current report quantifies how such scale-up methods impact the cost of production.

Figure 10: Scale-up models used in this study, described in detail in our companion report on energy demand for emissions reduction compliance.



Aggregation scenario 1:
Bio-methane is produced in multiple small plants, each comprising a small anaerobic digester and a small upgrader. Each plant collects biomass from the nearby area; biomass is transported over the same short transport distance. Bio-methane is aggregated via the natural gas network, which transports bio-methane under pressure.



Aggregation scenario 2:
Biogas is produced in multiple small anaerobic digesters. Each plant collects biomass from the nearby area; biomass is transported over the same short transport distance. Biogas is aggregated via dedicated biogas pipelines to a centralized upgrading facility, which produces bio-methane.

Aggregation scenario 3:
Bio-methane is produced in a large anaerobic digester. The plant collects biomass from a large area; consequently, biomass is transported over long distances. The plant also comprises a large upgrading facility, which produces bio-methane.

Based on the original data from the BioV plant, we have modeled the costs of:

a. biogas production
b. bio-methane production and injection into the natural gas grid (i.e., biogas production and upgrading, compression of bio-methane to 40 bar, and injection into the grid)

for plants with varying bio-methane production capacities.

Licensor information on capital costs at various capacities was not available. Therefore, we have modeled the cost of production for higher production capacities by scaling the investment costs and fixed costs from BioV according to the 0.6 rule (investment costs scale proportionally to capacity raised to the 0.6 power).[3]

In addition, our original information provides only the collective total cost of investment for upgrading, compression, and grid injection. Therefore, we have calculated the upscaled cost of:

c. bio-methane production (i.e., biogas, biogas upgrading, but no compression, no injection in the grid) by assuming that the investment costs for upgrading alone amount to half of the total investment costs for upgrading, compression, and injection.

The modeled costs of biogas and bio-methane production serve as input to our modeling of liquefaction and bio-methanol and SNG manufacture, which are described in subsequent sections.

3.3.1 Economy of scale for biogas production assuming constant transport contribution

Figure 11 and Figure 12 show the change in relative cost of production (EUR/MWh) of biogas and bio-methane, respectively, based on changing production capacity. These calculations assume that the cost of biomass and digestate transport is proportional to the production capacity.

Figure 11: Cost of biogas production at various production capacities (as Nm^3/h bio-methane in biogas). Transport costs are assumed to be proportional to the production capacity.

Production cost of biogas (EUR/MWh)

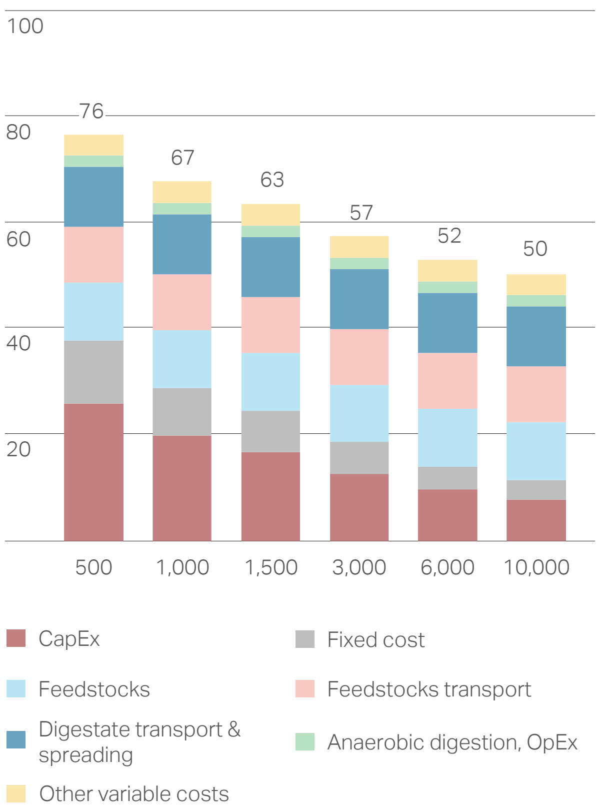
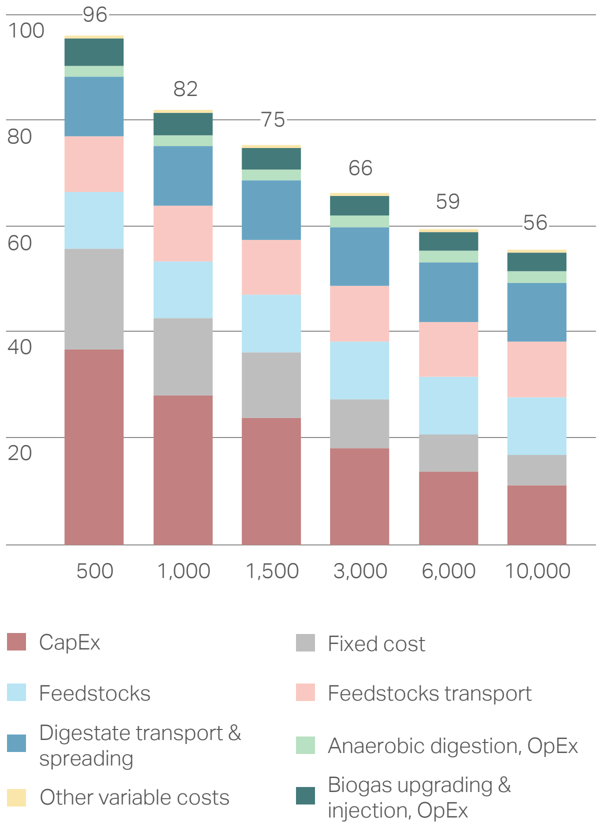


Figure 12: Cost of bio-methane production at various production capacities (as Nm^3/h bio-methane). Bio-methane is compressed and prepared for grid injection. Transport costs are assumed to be proportional to the production capacity.

Production cost of bio-methane (EUR/MWh)



Our modeling shows that the cost of biogas production decreases from around 80 EUR/MWh to 50 EUR/MWh when the plant capacity is increased from 500 to 10,000 Nm^3/h bio-methane in biogas (corresponding to 5-100 MWh/h). Upgrading, compression, and injection into the grid increase the cost of production by around 26% at a bio-methane production rate of 500 Nm^3/h, with this increase falling gradually to 12% at a capacity of 10,000 Nm^3/h. Today, the largest commercial biogas plants have a bio-methane production rate of about 6,000 Nm^3/h, corresponding to a biogas production rate of 10,000 Nm^3/h (see our companion report on insights into the value chain).

If the "0.6 rule"[3] is applicable to anaerobic digestion, as we have assumed here, then increasing plant capacity seems to be a very effective method to reduce both the overall cost of production and the impact of CapEx and fixed costs on the total. Specifically, when the plant production capacity is increased from 500 to 10,000 Nm³/h, the relative contribution of CapEx and fixed costs to the total production cost falls from 50% to 25% for the biogas case and from 58% to 30% for the grid-ready bio-methane case.

Importantly, it remains to be proven that the 0.6 rule is applicable. We found only one public study on the economy of scale of biogas plants.[10] Those authors' results show CapEx and fixed costs decreasing with production capacity in a less pronounced manner than we have assumed. However, the previous study analyzed a sample of commercial plants with diverse layouts and therefore is not fully comparable with our results.

3.3.2 Economy of scale for biogas production assuming variable transport contribution

If increased production capacity must be achieved by aggregating more biomass locally, and assuming that the biomass density per acreage is constant, then the need for more biomass means that biomass must be aggregated from a larger area. This implies that biomass must be transported over longer distances, and hence the cost of transport increases with increasing plant capacity (diseconomy of scale). We have described the model for this scale-up scenario in Appendix A of our report on energy demand for emissions reduction compliance.

In Figure 13, we show the impact of transport and other selected cost components on the cost of bio-methane production, expressed in EUR per MWh. Diseconomy of scale in biomass processing is known from the literature. One example is the work of Skovgaard and Jacobsen, who reported similar results based on OpEx data from commercial plants.[10]

Figure 13: Bio-methane production costs vs. plant capacity. CapEx costs are scaled as described in Section 3.3.1. With reference to Figure 12, "OpEx" is the sum of fixed operating costs and all variable costs; "Feedstock supply and transport" is the sum of "feedstocks" and "feedstock transport". "Digestate transport" also includes digestate spreading.

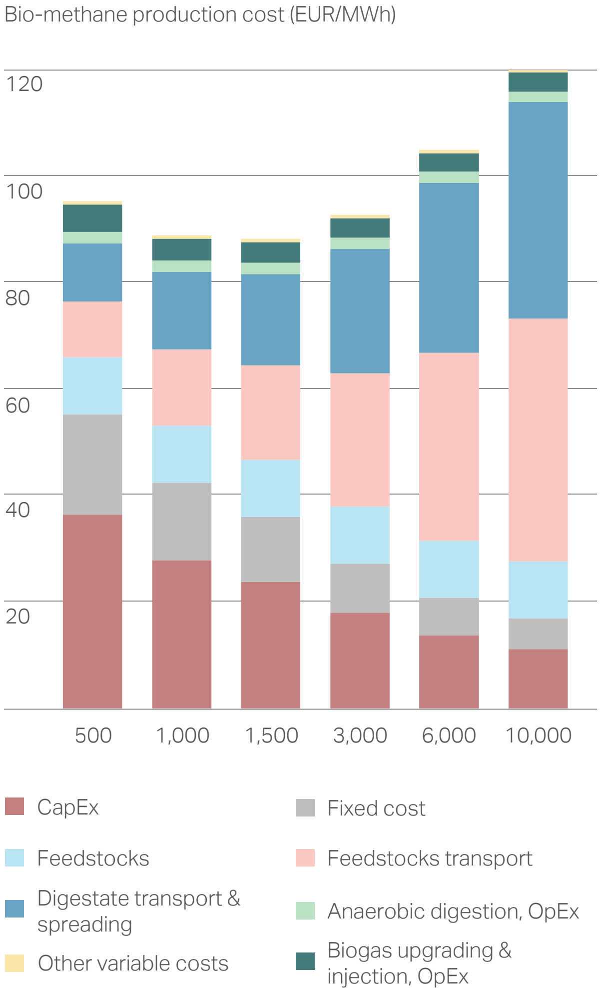


Figure 13 highlights that scaling up biogas production by aggregating large amounts of biomass carries penalties in terms of transport costs for biomass and digestate. The combination of increased transport costs and decreased CapEx and fixed costs with increasing production capacity suggests an optimum in terms of minimum cost per MWh of bio-methane. Under the assumptions of this study, this minimum is around a production capacity of 1,500 Nm³/h of bio-methane (corresponding to a biogas production capacity of approximately 2,500 Nm³/h). This result points to transport as a hotspot to consider when making decisions about plant location and biomass sourcing.

3.3.3 Cost of biogas and bio-methane transport via pipelines

Transport of biogas and bio-methane by pipeline offers other opportunities for scale-up. We have established techno-economic models for the capital investment related to laying of two types of pipeline:

1. Steel pipelines, which transport compressed bio-methane from a biogas upgrading unit to the natural gas grid or to a centralized polishing/liquefaction plant

2. PVC pipelines, which transport low-pressure (maximum 8 bar) dewatered biogas for further upgrading and/or chemicals manufacturing and liquefaction

Our pipelaying model comprises:

- Dependence of pipeline diameter on gas flow
- Dependence of installation costs upon the pipeline diameter
- Pipeline length of 1-10 km*

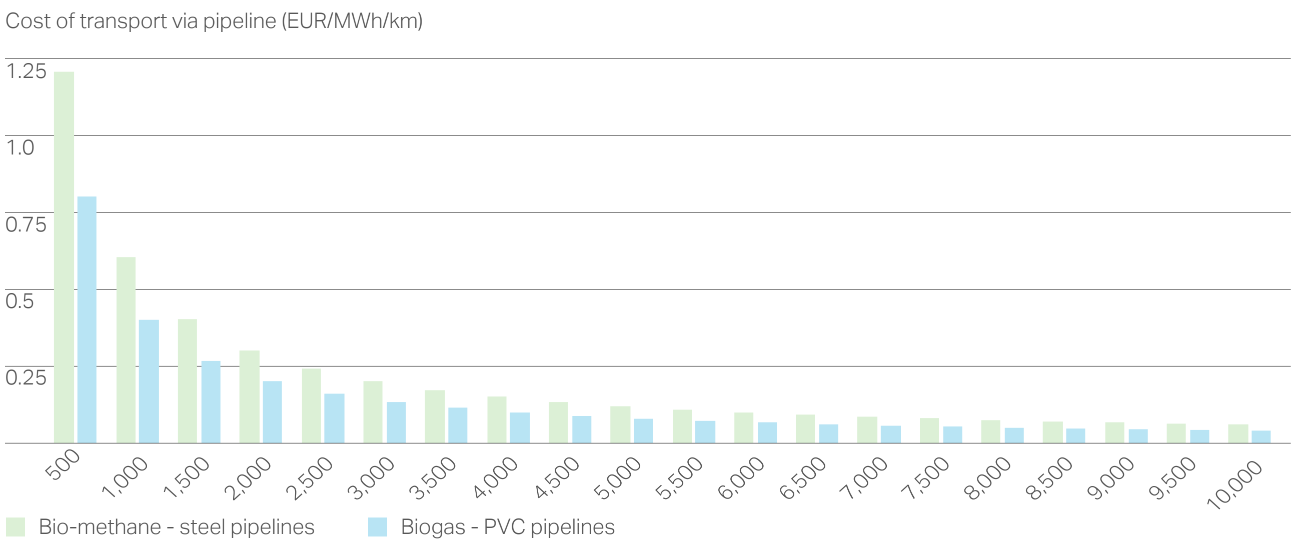
We sourced public data to use in the models.[11,12,13] The models do not include estimates of costs for permit and land, and pipeline operation.

Figure 14 shows the cost impact of installing pipelines for bio-methane (steel pipelines) and biogas (PVC pipelines). The horizontal axis represents the gas flowrate, which determines pipeline dimensions. Since biogas only contains ~60% methane, a given flow of biogas carries 40% less energy than the same flow of bio-methane. We have accounted for this difference by expressing the cost of transport via pipeline per unit energy in the vertical axis. The cost of pipelaying is proportional to the pipeline length. The vertical axis shows cost of transport via pipeline (in EUR) per unit energy (in MWh) and unit distance (in km).

As shown in Figure 14, transport and distribution of compressed bio-methane via a steel pipeline adds approximately 1.2 EUR/MWh/km for a small bio-methane flowrate of 500 Nm^3/h. The cost contribution due to transport rapidly falls with increasing transport capacity, becoming less than 0.2 EUR/MWh/km for 3,000 Nm^3/h and less than 0.1 EUR/MWh/km for 6,000 Nm^3/h.

Figure 14 also shows that transport of biogas via pipeline is cheaper than transport of bio-methane, even accounting for the lower energy density of biogas. This cost ranges from 0.8 EUR/MWh/km to transport biogas with a flowrate of 500 Nm^3/h to less than 0.13 EUR/MWh/km for a capacity of 3,000 Nm^3/h and 0.07 EUR/MWh/km (for 6,000 Nm^3/h biogas).

Figure 14: Cost impact of pipeline transport on bio-methane and biogas at various transport capacities.



* A maximum length of 10 km is typical for a "feeder" pipeline into a natural gas transmission or distribution system.

3.3.4 Putting it all together: how pipelines can reduce the cost of production

The results of Sections 3.1-3.3 can be put together to show how pipelines can help reduce the cost of bio-methane production. We calculated the production cost of grid-ready bio-methane for the three scale-up models described in Section 3.3.

Figure 15 shows the results of these calculations. For aggregation scenarios 1 and 2, we have assumed that the final bio-methane capacity, charted on the horizontal axis, is obtained by aggregating bio-methane (aggregation scenario 1) or biogas (aggregation scenario 2) produced from *two* identical plants connected through a new (installed for the purpose) 10-kilometer pipeline. The vertical axis illustrates the cost component per unit of biofuel energy.

Figure 15 clearly shows that, given our assumption that connecting pipelines have a fixed length of 10 km, aggregation scenarios 1 and 2 respond solely to economy of scale, while aggregation scenario 3 also responds to diseconomy of scale due to the high cost of feedstock and digestate transport.

A comparison of the charts reveals that, within the assumptions of this study, aggregating capacity from two 500 Nm³/h production plants via new pipelines (aggregation scenarios 1 and 2) is not cost-effective with respect to building a small/medium bio-methane plant with a production capacity of around 1,000 Nm³/h (aggregation scenario 3). However, aggregating bio-methane production capacities of 1,500 Nm³/h and beyond via new pipelines may be more convenient than building a large 3,000 Nm³/h bio-methane production facility. This is due to the large costs of transporting feedstock and delivering digestate to agricultural fields in the latter case and the improved economy of gas transport via pipeline achieved with higher gas capacity.

Figure 15: Comparison of bio-methane manufacturing costs based on production capacity and scale-up strategies described in Figure 10. For aggregation scenarios 1 and 2, the aggregated bio-methane capacity of the horizontal axis is obtained from two half-sized bio-methane / biogas production plants.

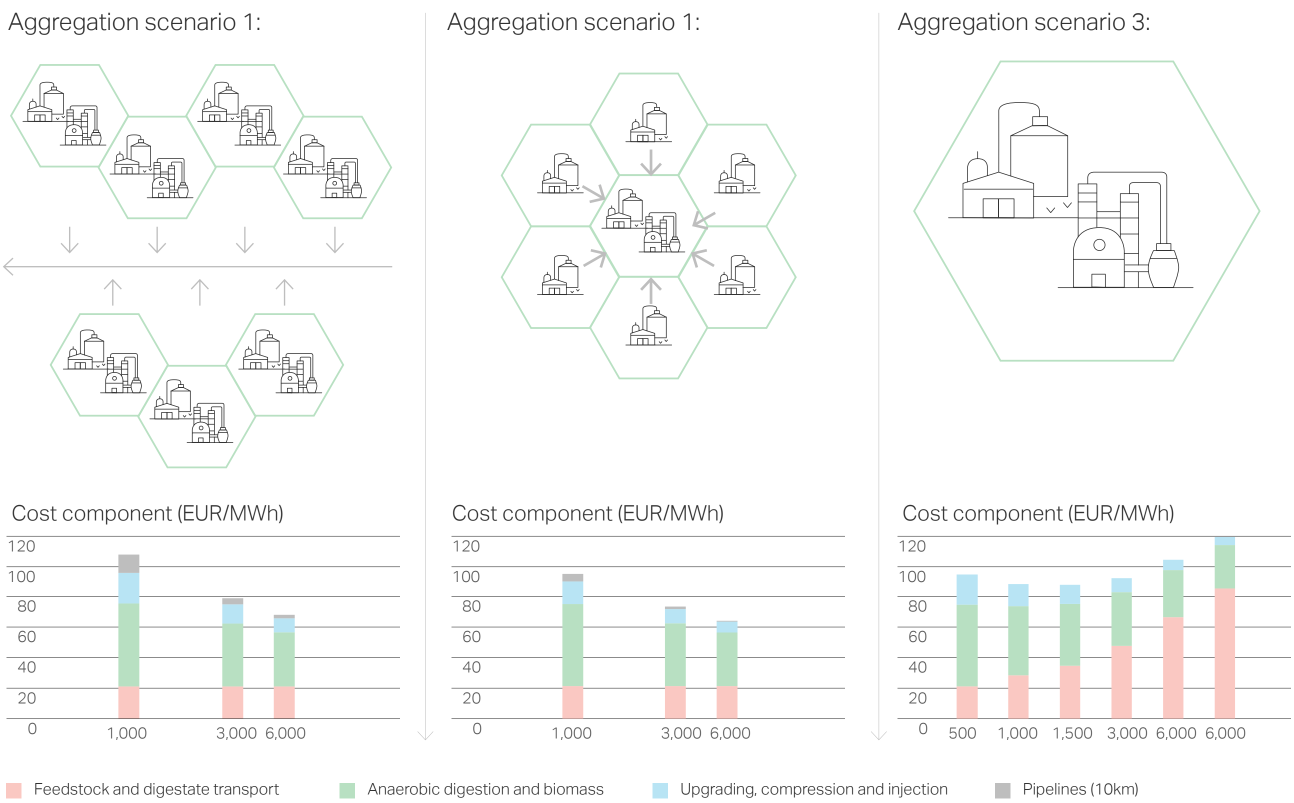
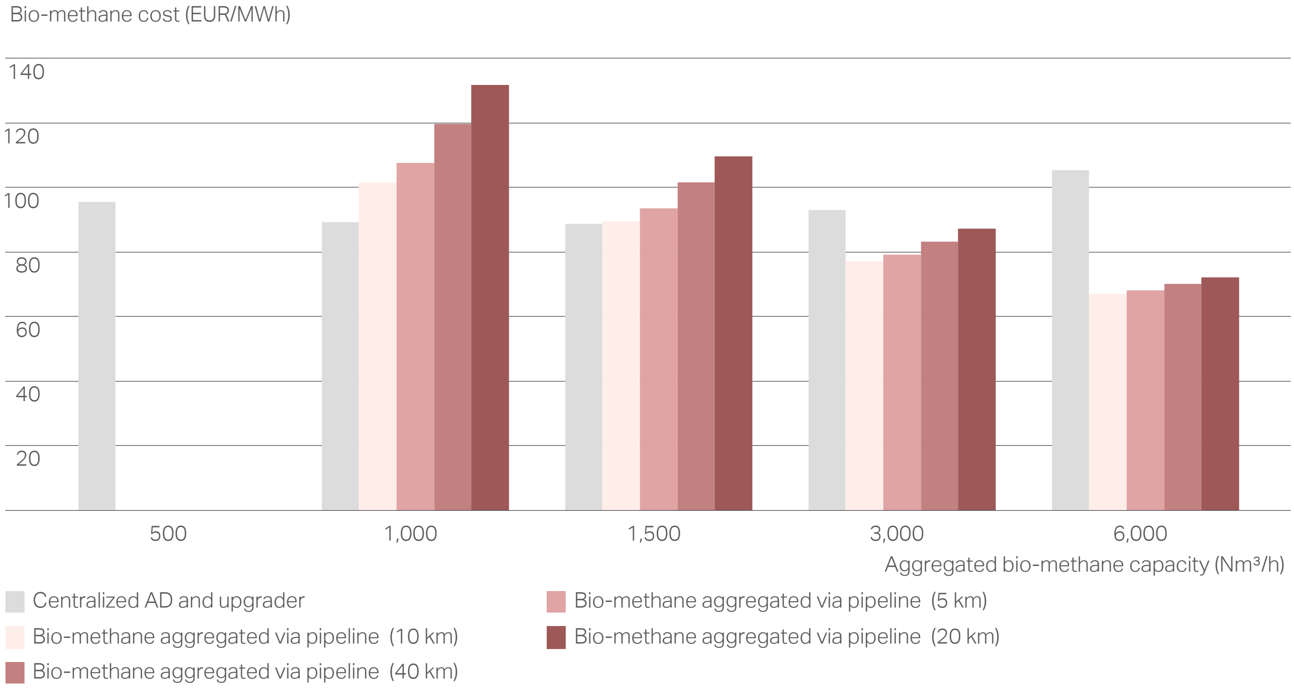


Figure 16: Effect of pipeline length on cost of bio-methane aggregated through bio-methane pipelines (aggregation scenario 1) compared with cost of production in centralized plants (aggregation scenario 3). For aggregation scenario 1, the aggregated bio-methane capacity of the horizontal axis is obtained from two half-sized bio-methane production plants.



Finally, Figure 16 shows the effect of pipeline length on the cost of bio-methane production when bio-methane is aggregated via bio-methane pipelines (aggregation scenario 1). With the assumptions of this study, we calculate that it is preferable to create an aggregated bio-methane production of, say, 3,000 Nm^3/h by building and operating two plants producing 1,500 Nm^3/h each and aggregating the production via a new pipeline instead of building and operating a single 3,000 Nm^3/h plant, even for a pipeline length beyond 40 km.

The cost reduction can be substantial: the production costs of 6,000 Nm^3/h bio-methane, corresponding to approximately 45,000 tonnes of oil equivalent, may be reduced by 30-40% if the product of two 3,000 Nm^3/h plants is aggregated via pipelines instead of building a 6,000 Nm^3/h centralized plant that aggregates biomass from a vast area. The trend is even more pronounced for larger capacities.

Since additional processes required to make biofuels suitable for shipping (e.g., liquefaction, methanol synthesis, and SNG production) have important economies of scale — as we will show in the next sections — the overall benefits of cheap aggregation methods for biogas and bio-methane are even more pronounced.

This analysis clearly indicates that one of the main hurdles to reducing the cost of producing biofuels from biogas — namely, the cost of amassing large amounts of feedstock and eliminating digestate in a sustainable manner — may be overcome by amassing bio-methane and biogas via pipelines instead.

The cost advantage is naturally even higher if suitable pipelines are already in place. Our companion report on energy demand for emissions reduction compliance describes how existing natural gas pipelines can be used to transport bio-methane between any two points of an interconnected natural gas grid if schemes to trade green certificates exist and mass balancing is accepted to qualify biofuels as low-carbon fuels. Furthermore, the ability to leverage existing infrastructure reduces or eliminates the time and natural resources required for pipelaying (land acquisition, permits, physical installation) — both of which are critical to limit climate change and other adverse impacts on the environment.

Thus, our analysis supports the position that acceptance of mass-balances for biogas-based biofuels for accounting purposes regarding emissions reduction calculations is critical for both accelerating the green shipping transition and for reducing its associated costs.

For the rest of this study, we have assumed that cost of transport is proportional to capacity.

3.4 Liquefaction

Liquefaction of bio-methane can either be integrated in a biogas upgrading plant or be done independently on, for example, methane pulled from the natural gas network. The first option allows a more efficient use of the energy involved in processing, while the second allows building of more economical larger plants.

Figure 17: Cost structure of biogas (left) and bio-methane (right) liquefaction at 10 MTPD (580 Nm³/h) LBM capacity.

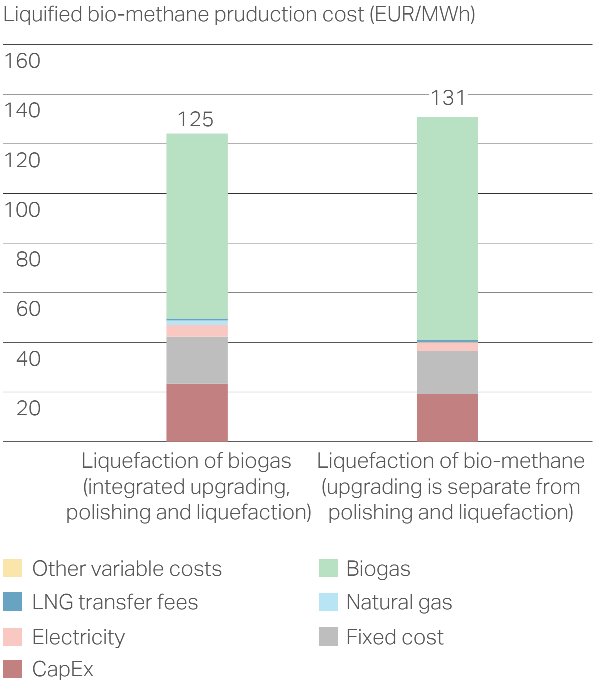


Figure 17 breaks down the cost structure of LBM production from both biogas (integrating upgrading, polishing, and liquefaction) and bio-methane (upgrading is separate from polishing and liquefaction) (Routes 1 and 2 in Section 2.1).

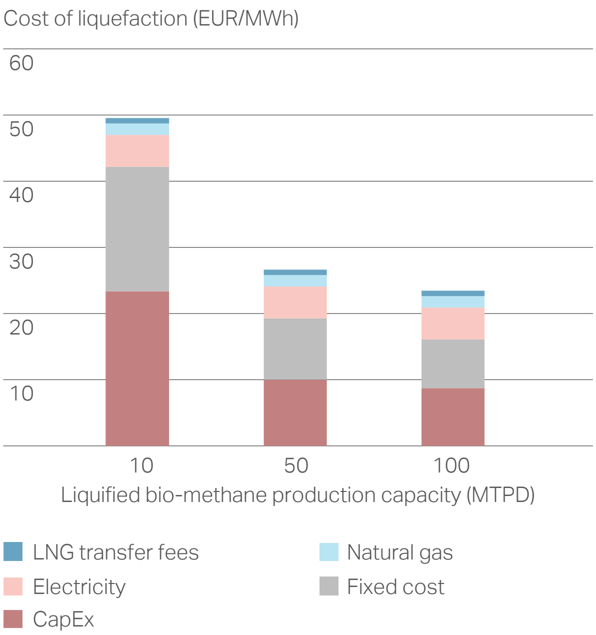
The analysis is carried out for an LBM production capacity of 10 metric tonnes per day (MTPD)†.
Our liquefaction model uses the cost of biogas manufacturing at the exit of the anaerobic digester as input. The figure shows that this cost component alone represents 50%–70% of the total cost of production for these processes (Figure 17). Thus, the most effective way to reduce the total cost of production of liquid bio-methane is to reduce the cost of biogas production.

Figure 17 also shows that integrating the liquefaction process with other processes of the bio-methane production value chain, particularly with upgrading,§ can afford some cost reduction with respect to decentralizing liquefaction and carrying it out independently. For a small liquefaction plant producing 10 MTPD of LBM, the cost savings from integration are 6% of production costs (see Figure 17, left-hand column).

Upgrading and liquefaction have important economies of scale. Amine scrubbing is the typical upgrading technology used for large biogas plants. We have modeled biogas production with integrated upgrading, polishing, and liquefaction at various biogas production capacities. Figure 18 shows the cost of upgrading, polishing, and liquefaction that must be added to the cost of biogas production for various biogas production capacities (expressed as biomethane both in MTPD and in Nm³/h). A potential cost reduction of 50% can be achieved by increasing capacity from 10 to 100 MTPD (580 to 5,800 Nm³/h), thanks to a decrease in CapEx and fixed costs. This result demonstrates the importance of aggregating capacity before further processing as a means to reduce cost of production.

† Equivalent to approximately 580 Nm³/h bio-methane capacity.
§ Here termed 'biogas liquefaction'.

Figure 18: Upgrading and liquefaction costs by plant size. Upgrading, polishing, and liquefaction applied to a biogas stream; biogas costs not shown.



3.5 Cost of SNG manufacturing: catalytic methanation of CO_2

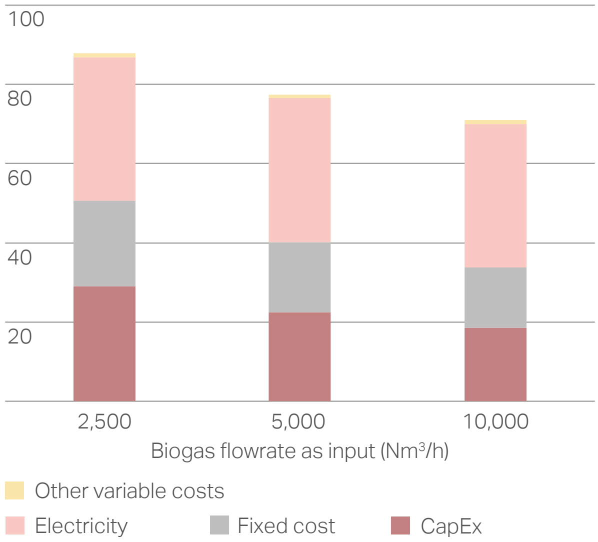
Biogas produced by anaerobic digestion contains approximately 50% biogenic CO_2, which is typically separated from bio-methane and released into the atmosphere. Alternatively, the biogenic CO_2 in biogas may be reacted with hydrogen to produce additional bio-methane, increasing the overall bio-methane production from the same biomass. This CO_2 methanation reaction can be enabled by synthetic catalysts or by bacteria. The resulting bio-methane gas is often referred to as synthetic natural gas (SNG). Here we use the term SNG to indicate the sum of bio-methane produced from anaerobic digestion (biogas) and CO_2 methanation. We discuss aspects, layouts, and performance of SNG manufacturing processes in more detail in our companion reports on energy demand for emission reduction compliance and WTW GHG emissions. For this report, we investigated the cost structure of biogas methanation for the catalytic route.

Catalytic methanation is a commercial technology widely applied in ammonia synthesis for gas cleaning. The technology is also applied to produce methane from solid fuels (coal or biomass).[1] To the best of our knowledge, however, this process has not yet been commercially applied to biogas. Catalytic methanation produces high-temperature heat as a reaction byproduct. As a result, it is optimally integrated with solid oxide electrolyzer cells (SOEC), which require heat.

Catalytic methanation has excellent conversion rates, and the residual CO_2 after this process is very low (details are confidential). One uncertainty in the process is managing the intermittent supply typical of renewable electricity. This is not a problem for plants connected to the electrical power grid; however, decentralized plants may require electricity storage. This was not considered in our calculations as the high cost of electricity storage makes them a less preferred option.

Figure 19 summarizes our techno-economic assessment of the additional cost of catalytic methanation. The figure does not show the cost of biogas manufacturing. Electricity is the single most important component of the added cost, and controlling the price of electricity is therefore mandatory for the economics of the plant. Consumption of electricity is not expected to change with a change in SNG production capacity. Also, if electricity is pulled from the power grid, we do not expect the electricity price to be sensitive to plant capacity. These two assumptions cause the contribution of electricity to the total cost of production to be constant. CapEx and fixed costs associated with SNG manufacturing, on the other hand, decrease with increasing production capacity.

Figure 19: Additional costs of catalytic methanation divided by the energy content of SNG product at various flowrates of input biogas. Cost of biogas is not shown. Costs of SNG transport, electricity storage and SNG liquefaction are not accounted for.



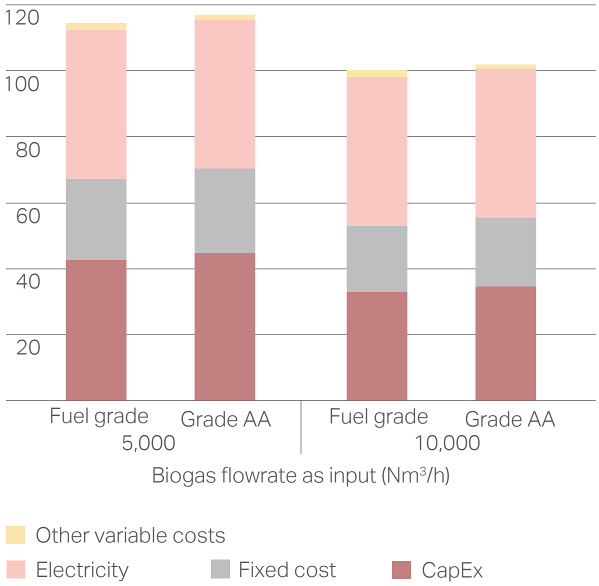
3.6 Cost of bio-methanol manufacturing from biogas

Bio-methanol may also be produced directly from biogas without previous removal of CO_2. Topsoe has developed processes for bio-methanol manufacturing based on eREACT™ technology.[1] This technology uses electrical power to reform methane into synthesis gas — the gas mix required for methanol synthesis. In our companion studies on energy demand for emissions reduction compliance and WTW GHG emissions, we also describe routes to bio-methanol manufacturing from biogas based on traditional reforming and the implications of process and supply chain choices on production and emissions intensity. Gasification routes to bio-methanol are not assessed in this series of reports.

Here, we investigated a biogas-based route to bio-methanol that maximizes use of biogas thanks to the addition of green hydrogen. We assessed the cost of production of two grades of methanol: fuel-grade, which includes some water and higher alcohols, and grade 'AA' methanol, which is highly purified. Additional details on both methanol grades are provided in our companion study on energy demand for emissions reduction compliance.

Similar to SNG manufacturing, electricity is the largest component of the additional costs of bio-methanol synthesis (see Figure 20). As discussed in Section 3.5, we do not expect the cost of electricity to be sensitive to capacity. Cost of CapEx and fixed costs — the other dominant components of the additional costs of bio-methanol synthesis — instead scale with capacity.

Figure 20: Additional costs of bio-methanol manufacturing from biogas divided by the energy content of bio-methanol at various flowrates of input biogas. Cost of biogas is not shown. Costs of transport of the finished product and any electricity storage are not accounted for.



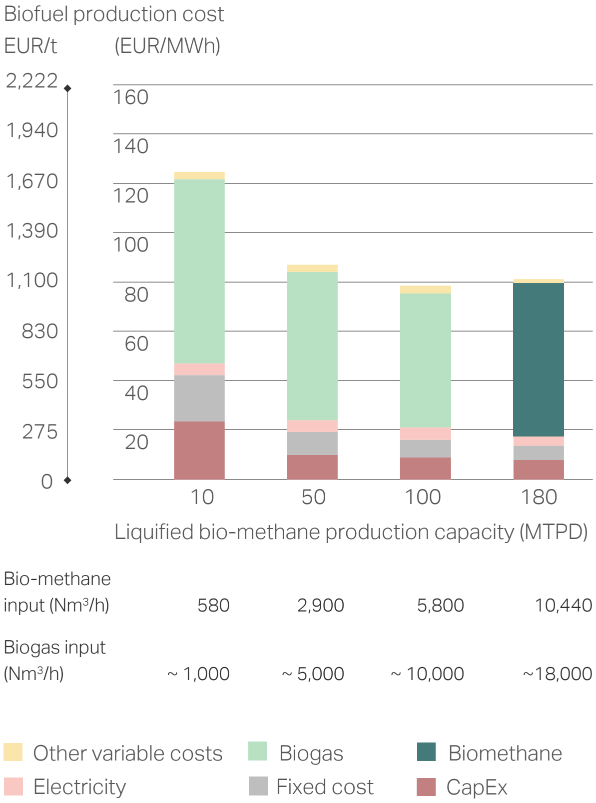
3.7 Overall cost of production of LBM and bio-methanol from biogas

Section 2.1 introduced various routes to LBM and bio-methanol production comprising different options for aggregation infrastructure and integration of processing units. Here, we bring together the results of our techno-economic modeling across these pathways to compare the overall cost of production for these maritime biofuels from biogas.

3.7.1 Biogas and bio-methane liquefaction

For a small, decentralized biogas plant with a bio-methane production of 580 Nm³/h, the overall cost of production — including anaerobic digestion, upgrading, and liquefaction at the same plant — is approximately 120-130 EUR/MWh, equivalent to 1,700-1,800 EUR/t or approximately 35-40 USD/GJ. The cost of production falls to around 80 EUR/MWh (1,100 EUR/t, 25 USD/GJ) if production capacities of 100 MTPD of LBM (approximately 10,000 Nm³/h biogas or 5,800 Nm³/h bio-methane) can be achieved. This range of production costs is in line with other studies.[5]

Figure 21: Cost of LBM at increasing liquefaction capacity. Unit cost of feedstock and digestate transport is assumed to be constant. LBM capacities up to 100 MTPD are obtained by liquefying biogas in integrated facilities. Above that, we assume that bio-methane is aggregated through pipelines (costs not added) and the liquefaction is centralized.



A capacity of 10,000 Nm³/h biogas is the current world scale, and we expect larger capacities to be achieved by bio-methane aggregation via pipelines. We accounted for additional costs of compression and injection in pipelines, but did not add costs for pipeline laying, instead assuming the existence of a pipeline network. Based on these hypotheses and the information from licensors, increasing liquefaction capacity to 180 MTPD does not notably decrease production costs. At even larger capacities, other liquefaction technologies may become affordable and a step change in the manufacturing costs of LBM is expected.[14]

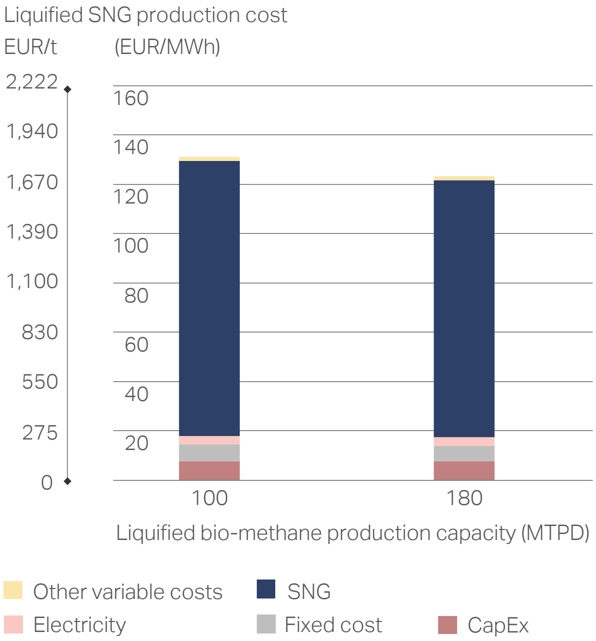
3.7.2 Upgrading, polishing, liquefaction, and CCS

LBM production routes producing an excess of CO_2 optimally lend themselves to carbon capture and storage (CCS). In these routes, CO_2 is already separated from methane, and so only CO_2 compression, transport, and storage are required.

Public literature from 2020-2021 suggest a cost of 50 EUR/t for CCS of a concentrated CO_2 stream (25-30 USD/t for capture, 20-25 USD/t for storage).[15,16] According to our model, the additional costs for CCS for a manufacturing plant producing 100 MTPD of LBM is in the range of 8 EUR/MWh, influenced by the economy of scale. In the overall summary of Section 3.8, we compare this route to the other routes to biofuels.

3.7.3 SNG liquefaction

Figure 22: Cost of LBM from liquefaction of SNG



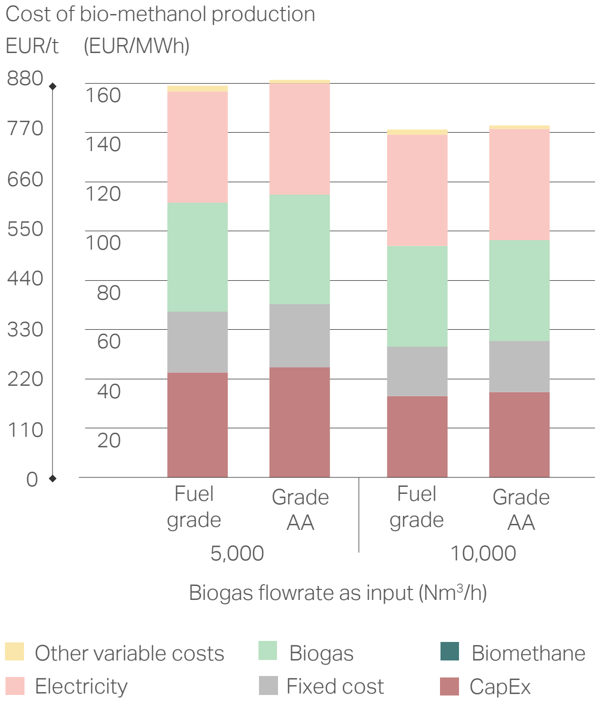
SNG input (Nm³/h)	5,800	10,440
Biogas input (Nm³/h)	~ 5,800	~ 10,440

Figure 22 shows the aggregated costs for SNG liquefaction. With an electricity price of 55 EUR/MWh, we find that liquefaction of SNG is more expensive than liquefaction of biogas or bio-methane at comparable capacity. A liquefaction plant delivering 100 MTPD LBM is fed with 5,800 Nm³/h SNG. Liquefaction of this volume of catalytic SNG costs around 130 EUR/MWh or 1,700 EUR/t. In comparison, liquefaction of 100 MTPD of biogas costs only 80 EUR/MWh (1,111 EUR/t, see Figure 21).

3.7.4 Bio-methanol manufacture

Figure 23 shows the production cost for manufacturing of methanol from biogas. We studied both fuel-grade bio-methanol (approximately 85% methanol) and grade 'AA' bio-methanol (close to 100% methanol) and found no appreciable difference in the manufacturing cost. Fuel-grade methanol has a low energy density, which means that more bunker volume is needed onboard. Considering the minimal differences in manufacturing cost, grade 'AA' bio-methanol seems to be a superior choice.

Figure 23: Cost of manufacturing for fuel-grade bio-methanol (85% methanol) and grade 'AA' bio-methanol (close to 100% methanol). Contribution of biogas is calculated per unit energy of bio-methanol and not unit energy of biogas as in Section 3.3.1.

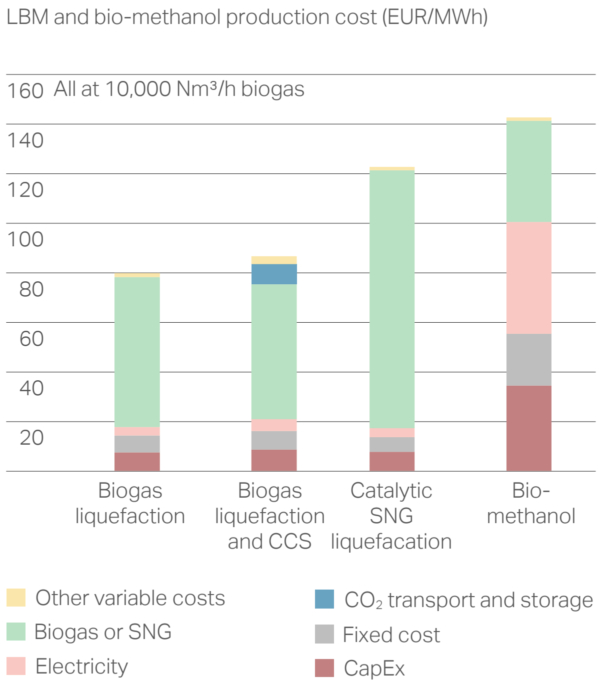


The manufacturing cost of grade 'AA' bio-methanol for a biogas capacity of 10,000 Nm³/h is 143 EUR/MWh, which is more expensive than both liquified catalytic SNG (123 EUR/MWh, see Figure 22) and liquified biogas (80 EUR/MWh, see Figure 21) at the same biogas input capacity. The manufacturing cost per tonne of grade 'AA' bio-methanol is lower than that of bio-methane due to methanol's lower energy density.

3.8 Cost of decarbonization

Figure 24 compares the overall manufacturing costs of LBM and bio-methanol for a biogas capacity of 10,000 Nm³/h. The commercial route to LBM based on biogas production in an anaerobic digester, upgrading, and liquefaction (Figure 24, left-most column) has the lowest production costs per unit energy. With the assumptions of this study, applying CCS has a modest impact on LBM manufacturing cost. SNG and bio-methanol from biogas are penalized by the high consumption of electricity and the cost of hydrogen manufacturing and catalytic synthesis. With the assumptions of this study, SNG and bio-methanol are more expensive on energy basis than the commercial route to LBM.

Figure 24: Manufacturing costs of LBM and bio-methanol based on a biogas input of 10,000 Nm³/h.



In our companion reports on energy demand for emission reduction compliance and WTW GHG emissions, we have shown that biofuel manufacturing pathways are characterized by a large variability in emissions intensity. On the whole, the emissions intensity of biofuel production depends on choices made throughout the supply chain, such as emissions intensity of electricity, biomass displacement, and control of methane emissions. Our accompanying report on energy demand for emissions reduction compliance further explains different biofuel pathways and emissions intensity cases.

Using the manufacturing costs calculated here, we can calculate the unit cost of decarbonization for select biofuel production pathways and emissions intensity scenarios. The correspondence between the examples in this report and the pathways described in energy demand for emissions reduction compliance is as follows:

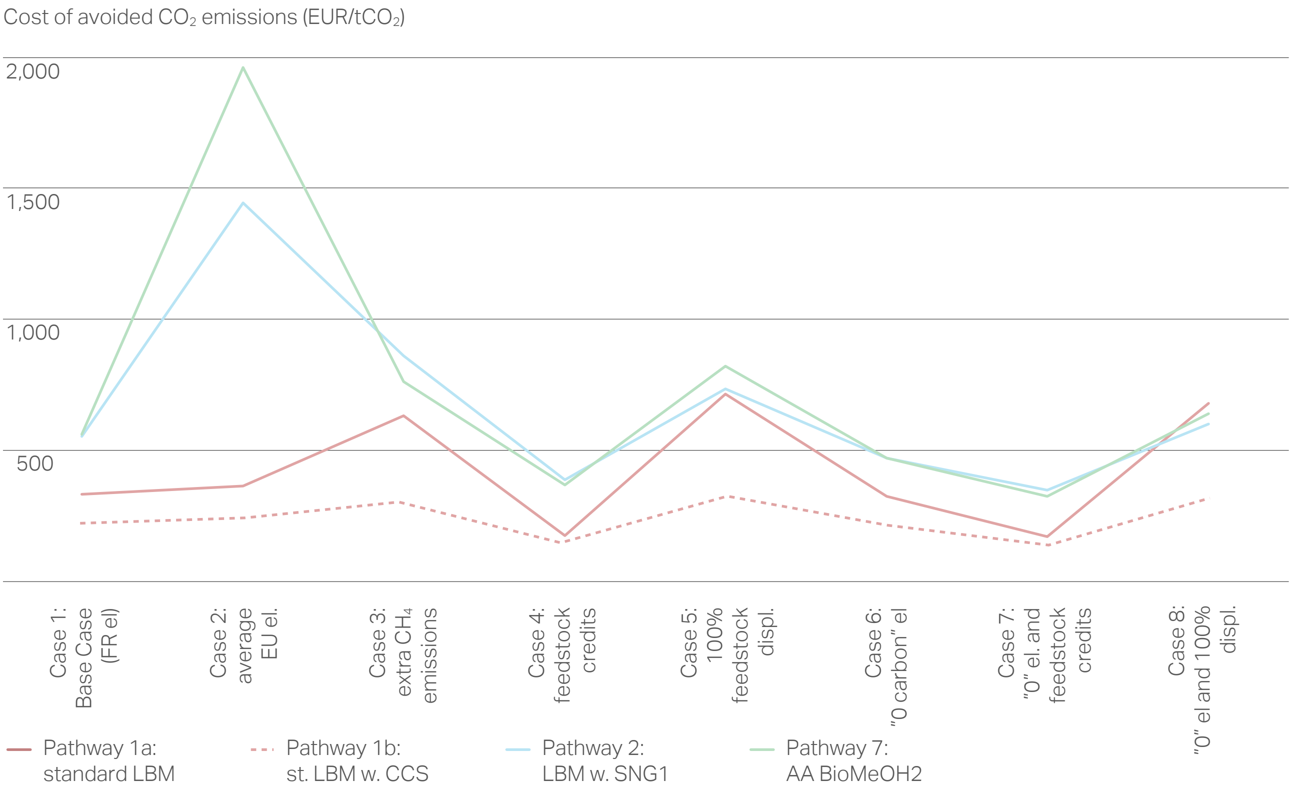
Techno-economic trends (this report)	Energy demand for emissions reduction compliance
Bio-methane liquefaction	Pathway 1a (standard LBM)
Bio-methane liquefaction & CCS	Pathway 1b (standard LBM with CCS)
Catalytic SNG liquefaction	Pathway 2 (SNG1)
Bio-methanol	Pathway 7 (AA BioMeOH2)

We define the unit cost of decarbonization as the cost of manufacturing a quantity of biofuel such that, when the biofuel replaces fossil fuel, GHG emissions are reduced by one tonne of CO_2 equivalent (CO_2eq). We calculated the unit cost of decarbonization as described in the Appendix of this report.

Figure 25 shows our calculated unit costs of decarbonization for different biofuel production pathways. Unit costs of decarbonization above 1,000 EUR/tonne are calculated for biofuels that do not meet the criteria to be eligble for compliance with FuelEU Maritime requirements.

Figure 25 underlines that, if carbon storage is available, then the standard LBM production with CCS (pink dashed line) is always the cheapest option for decarbonization. The second-cheapest option is the standard LBM without CCS (solid pink line), even though the unit cost of decarbonization may be twice as high as the same pathway with CCS. With the cost of electricity used in this study, the unit costs of decarbonization via liquified SNG and bio-methanol (blue and green lines, respectively) are significantly more than standard LBM in most cases.

Figure 25: Unit costs of decarbonization for various biofuels. For detailed explanation of pathways and cases, please refer to the companion reports on energy demand for emissions reduction compliance and WTW GHG emissions.



4. Conclusion

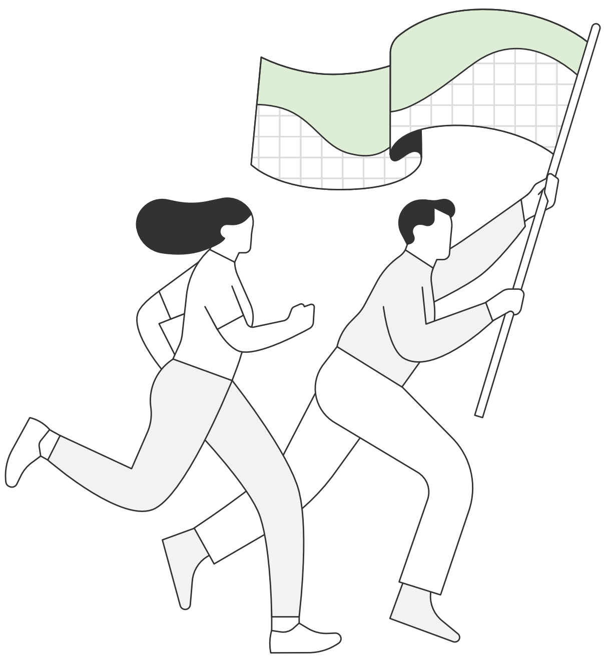
This study reports on the economic performance of theoretical biogas-based value chains to supply shipping with LBM (liquified bio-methane), fuel-grade bio-methanol, and grade 'AA' bio-methanol as bunker fuels. The study, which was based largely on industrial knowledge shared by technology providers, investigated both commercially available technologies (the standard route to biogas upgrading and liquefaction) and emerging advanced technologies that enhance the biofuel production process using green hydrogen. Our ambition was to achieve a qualitative understanding of both the costs of manufacturing and the hotspots in terms of cost sensitivity, and to reflect on costs in terms of climate performance.

The routes to marine biofuels in this study have both economies of scale, which affect CapEx and fixed costs, and diseconomies of scale, which affect transport of feedstocks and digestate. Therefore, the type and location of a biogas plant with respect to the biomass feedstock and digestate recipients may have a strong effect on the plant's profitability. Controlling biomass and digestate management options is critical. Economies of scale for some of the technologies in the supply chain are weak. Therefore, we can infer that there are optimum sizes for biofuel plants.

Using pipelines to transport and aggregate biogas or bio-methane can help reduce manufacturing costs greatly, even more so if such pipelines already exist. Existing pipelines are typically part of the natural gas network carrying methane of fossil origin. Piggybacking on this physical infrastructure can be done if a virtual infrastructure comprising trading of green certificates and mass balancing is in place. Thus, approval of mass balancing as a tool to manufacture biofuels can be critical to control the costs of biofuels.

We find that the standard commercial process to manufacture LBM via upgrading and liquefaction of biogas is the cheapest of the options considered, with a manufacturing cost of approximately 80–130 EUR/MWh (1,100–1,800 EUR/t). At comparable sizes, SNG and bio-methanol are 50%–70% more expensive if assuming an electricity price of 55 EUR/MWh.

The standard commercial LBM production process also has the lowest unit cost of decarbonization, at 200-700 EUR per tonne of CO_2 removed. In terms of environmental performance, the standard commercial process is particularly strong if CO_2 can be captured and stored. In this arrangement, the unit cost of decarbonization is 200-300 EUR/t. In comparison, the unit cost of decarbonization for SNG and bio-methanol is above 400 EUR/t. Attractive unit costs of decarbonization can only be achieved if the entire supply chain (comprising manufacturing facilities and the ship) practices excellence in avoiding methane emissions.



5. The project team

This report was prepared by the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping (MMMCZCS) with assistance from our partners. Team members marked with an asterix (*) were seconded to the MMMCZCS from partner organizations.

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Abbreviations

BioV	Biovilleneuvois reference biogas plant
CapEx	Capital expenditures
CCS	Carbon capture and storage
CH_4	Methane
CO_2	Carbon dioxide
CO_2eq	Carbon dioxide equivalent
eREACT™	Electrical steam methane reforming
GHG	Greenhouse gas
GJ	Giga joule
h	Hour
km	Kilometer
LBM	Liquified bio-methane, also known as liquified biogas (LBG) or bio-LNG
LNG	Liquified natural gas
MJ	Mega (1x10^6) joule
MMMCZCS	Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping
MTPD	Metric tons per day
MWh	Megawatt hour
Nm^3/h	Normal cubic meters per hour
OpEx	Operating expenses
PVC	Polyvinyl chloride
SNG	Synthetic natural gas
SOEC	Solid oxide electrolyzer cells
t	Tonne (also known as metric ton = 1,000 kg)
TJ	Tera (1x10^12) joule
WTW	Well-to-wake
y	Year

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Appendix: Method for calculating unit cost of decarbonization

For the purposes of our analysis shown in Section 3.8, the unit cost of decarbonization was calculated from mass and energy balances using the following equations:

1) $E_{F0} = E_{F1} + E_{B1}$

2) $GHGe_0 - GHGe_1 = 1t = GHGe_{F0} - GHGe_{F1} + GHGe_{B1} = (EI_F \times E_{F0} - (EI_F \times E_{F1} + EI_B \times E_{B1}))$

Combining 1 and 2:

3) $1t = (EI_F - EI_B) \times E_{B1} \times 10^{-3}$ and $E_{B1} = (1 \times 10^3)/(EI_F - EI_B))$

The unit cost of decarbonization is the cost for manufacturing E_{B1}:

4) $UC = C_B/3.6 \times E_{B1} = C_B \times 10^3/(3.6 \times (EI_F - EI_B))$

Where:	
$_0$	reference time
$_1$	current time
$_B$	biofuel
C	the cost of manufacturing in EUR/MWh
EI	emissions intensity in $gCO_2eq/MJ = kgCO_2eq/GJ = tCO_2eq/TJ$
E	yearly energy, in GJ/y
$_F$	means fossil marine fuel
GHGe	yearly greenhouse gas emissions, in tCO_2eq/y
UC	the unit cost of decarbonization EUR/t
$_T$	means total

Using the emissions intensity of the fossil fuel comparator as reference for the fossil marine fuel (EI_F = 91.16 gCO_2eq/MJ), we obtain unit costs of decarbonization depicted in Figure 25.

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