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Renewable Methanol from Industrial Carbon Emissions: A Dead End or Sustainable Way Forward?

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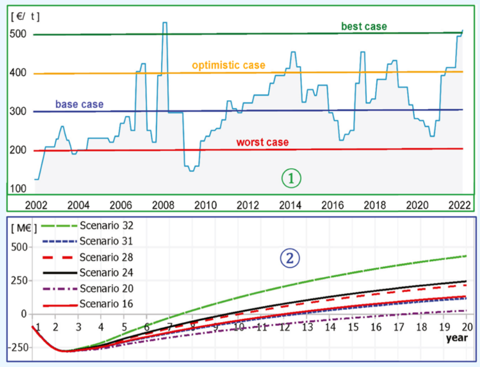
ABSTRACT: As the urgency to achieve net-zero emissions by 2050 intensifies, industries face an imperative to reimagine their role in the fight against climate change. One promising avenue arises from the realization that industrial emissions, often deemed pollutants, can be the building blocks of a circular economy strategy. By directly utilizing these carbon emissions as raw materials, we can produce net-zero or low-carbon fuels, carbonates, polymers, and chemicals. At the heart of this paradigm shift lies the production of carbon-neutral methanol from industrial flue gas—a technically viable approach that has gained significant momentum in recent years. The conditions under which such a circular economy model for producing renewable methanol becomes commercially sustainable based on realistic constraints, however, are not sufficiently explored in the existing literature. This paper fills this gap by investigating if and when net-zero methanol production from industrial flue gas will be a sustainable long-term strategy. Using detailed technoeconomic modeling of integrated hydrogen and methanol production ecosystems for two production capacities, I will evaluate 32 practical production scenarios using realistic regulatory, economic, and market conditions. Even though renewable methanol from industrial emissions can be a viable technical solution to address climate change and global warming, I will show why this strategy will be commercially feasible only under favorable economic, regulatory, and market conditions. Furthermore, I will demonstrate how the market price of methanol and the cost of carbon-free electricity critically influence the commercial feasibility of this approach. When these two parameters are unfavorable, I will show why other factors, namely, carbon credits and byproduct (oxygen) sales, will not be sufficient to create an economically sustainable circular economy of renewable methanol from industrial emissions. Finally, I will provide arguments on why one has to think through stakeholder cooperation and public−private partnerships to mitigate various project risks. Despite the importance of this topic, it is not sufficiently covered in the available scientific literature. To advance policy and regulatory frameworks in this area, I strongly believe that further research and development is needed. I will also share perspectives on regulatory derisking mechanisms, which can help align regulations with private investors' preferences. With the analyses and arguments showcased in this paper, I will firmly assert that without favorable conditions, strong partnerships, and stakeholder cooperation, the production of renewable net-zero methanol from industrial emissions risks becoming a dead-end strategy.



■ INTRODUCTION

Increasing concentrations of greenhouse gases (GHGs), particularly carbon dioxide (CO_2), in the atmosphere result in global warming and accelerate climate change. Human activities are a major cause of increased CO_2 concentration in the atmosphere. The European Union, in particular, demands concrete and immediate actions from industries and governments to step by step reduce carbon footprints in the coming years and plans for transition toward carbon-free, and even carbon-negative, alternative technologies.[1,2] In Figure 1, CO_2 emissions from industrial operations including energy and heat production in six major fossil-fuel-consuming economies are presented based on reported data in the last 100 years between 1920 and 2020.[3] Despite several efforts to reduce GHG emissions, the overall global emission trend is very disturbing. The implications of inaction or delay in implementing solutions will be devastating. We need to act urgently and implement possible solutions that have a sustainable impact on mitigating industrial emissions. If we follow the course of actions based on existing current policies alone, we will not be able to reach the target of 1.5 °C by 2100. We may have already lost our chances of getting to 1.5 °C. Although collectively our aim is still to limit global warming to well below 2 °C as laid out in the Paris Agreement, current trends confirm that we are clearly far off-

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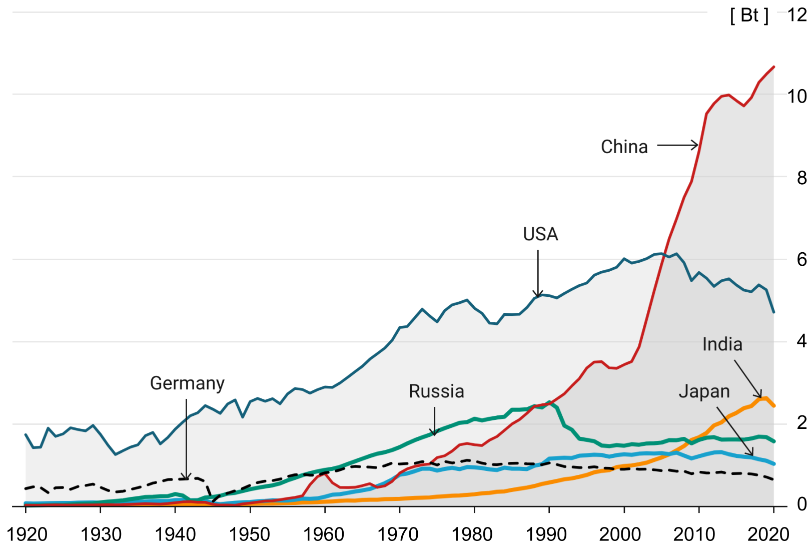

Figure 1. Annual CO_2 emissions in billions of tonnes that include electricity and heat generation and various manufacturing and industrial operations in six major fossil-fuel-consuming economies.

track.[4,5] Hence, multiple actions guaranteeing net-zero and negative carbon levels are simultaneously required to significantly reduce our present emission levels. Several estimates are presented based on different scenarios.

Furthermore, pathways to dramatically reduce future emissions are also fraught with technical and economic challenges. The developing economies are increasingly dependent on fossil fuels for driving their economy—mainly China with some contributions from India. The availability of cheap oil and the desire for growth accelerate the rate of increase in GHG emissions in these countries.[6] The last 20-year trend confirms that industrial carbon emissions may not reduce in the short- and medium-term anywhere close to the ideal limits. This is also reflected in the oil and gas production, import, and consumption patterns of these countries. In the developed economies, especially in Europe, countries have common agreements to drastically reduce carbon emissions. That being said, in the short- and medium-term, we have to depend on technologies that deal directly with carbon emissions because we are still heavily dependent on fossil fuels for industries, transport, and utilities. Presently, we have two approaches to directly deal with industrial carbon emissions, namely, carbon capture and storage (CCS)[7−10] and carbon capture and utilization (CCU) technologies.[11−15]

CCS technologies are still in their early stages of impact evaluation. Long-term impacts of permanently storing CO_2 deep beneath the Earth's crust are still unknown.[16] Particularly, deep-ocean carbon storage is known to extremely acidify and increase the concentration of CO_2 in deep-ocean waters.[17,18] Storing carbon emissions beneath ocean floors might not be an eco-friendly solution as oceans already face other human-induced pollutions in the form of plastic wastes, illegal oil spills, and refinery accidents.[19,20]

Carbon capture and utilization (CCU) technologies, on the other hand, provide environmentally safe alternatives as we directly convert carbon emissions into value-added products. Innovations in carbon utilization are driving a circular carbon economy. These innovations aim to reduce the consumption of fossil-based raw materials. CCU pathways have been studied in the past to examine their technical potential to transform certain industries such as chemicals into a carbon-neutral sector by decoupling operations from fossil fuels.[21] Technically, CCU could potentially support the energy transition by enabling power-to-liquid or power-to-gas approaches and contributing to a circular economy by converting waste emissions into different value-added raw materials.

In particular, methanol production methods using carbon emissions from industries have been extensively studied.[22−29] Renewable methanol offers significant advantages over fossil fuels in carbon emissions reduction. Depending on the feedstock and conversion process, it can achieve carbon emission reductions ranging from 65 to 95%.[30−34] This places renewable methanol among the most promising alternatives to gasoline, diesel, coal, and methane, with one of the highest potential reduction rates.[35,36] Earlier research has also shown some of the main challenges and opportunities along potential supply chains of renewable methanol, especially for maritime shipping focused on biomethanol.[24] Furthermore, pure methanol combustion generates minimal emissions of sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter, making it an environmentally favorable option.[31,37]

Only a few works in the past have explored the economic assessment of a methanol production plant with procured hydrogen or using an integrated hydrogen production unit.[38−49] Whenever such economic assessments are presented, they do not take into account realistic scenarios. Instead, they tend to focus on hypothetical price levels for raw materials, products, and byproducts that are far-fetched from market realities. Our main goal in this paper is to fill these gaps by investigating the economic feasibility of an integrated hydrogen and methanol production ecosystem. I have investigated two different capacities under realistic economic and market conditions. I have also discussed if and when industrial carbon emission credits (emission taxes) can impact the overall economic feasibility of an integrated hydrogen and methanol production ecosystem. Depending on market and economic conditions, the circular economy of industrial carbon emissions to produce methanol can either lead to a dead end (commercially not feasible) or a sustainable way forward. Hence, I have discussed the role of supply- and value-chain integration to create favorable market and economic conditions for a combined

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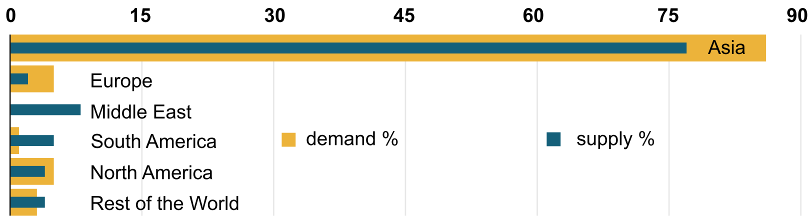

Figure 2. Demand and supply of methanol across different regions as of 2020.

hydrogen and methanol production ecosystem utilizing industrial carbon emissions.

MARKET, ECONOMY, AND REGULATION

Over the last few decades, market opportunities for methanol have evolved to a point where it is an inevitable raw material for many industrial applications. Global annual methanol production capacity is expected to double in 11 years from 2020 to 2030. This corresponds to an increase from ∼157 million tonnes [Mt] in 2020 to around 311 Mt by 2030. This is mainly due to several planned and announced methanol production plants that are expected to be fully functional between now and 2030 in the Asia and Former Soviet Union region. Most of these plants would follow the traditional route to produce gray and blue methanol. Figure 2 shows various regional demand and supply of methanol as of 2020.

The top five methanol exporting and importing countries and their respective market shares for 2020 are given in Tables 1 and 2, respectively.

Table 1. Top Five Methanol Exporters in the World in 2020[50]

country	export value [$ million]	% of world exports
Saudi Arabia	948	23.0
USA	721	18.0
Netherlands	525	13.1
Russia	378	9.4
Malaysia	293	7.3

Table 2. Top Five Methanol Importers in the World in 2020[50]

country	import value [$ million]	% of world imports
China	2690	32.0
USA	570	6.8
India	489	5.9
Netherlands	435	5.2
South Korea	421	5.0

It is worth mentioning that Trinidad and Tobago is a major petrochemical hub. It was the world's largest exporter of methanol from a single country as of 2019. With the closure of methanol capacity in 2020, this is no longer the case. In 2019, Trinidad and Tobago's methanol export trade accounted for $1.39 billion compared to the second position $1.28 billion (Saudi Arabia). In 2019, India's methanol import value was $574 million behind both the Netherlands ($643 million) and South Korea ($626 million). As you can see in ref 2, in 2020, India overtook both the Netherlands and South Korea in terms of methanol imports.

Market prices for methanol have been highly volatile in the last 20 years as shown in Figure 3.[51] I have highlighted four price levels as best, optimistic, base, and worst case in Figure 3 based on 20-year historical methanol prices. As part of the technoeconomic assessment presented in this paper, I will use prices corresponding to these four cases. To understand the methanol price volatility, we need to briefly discuss relevant applications and regions that drive global methanol demand and supply.

The Asia-Pacific region is the world's largest methanol market. China and India are the two largest consumers of methanol and methanol-based fuels. For example, China has made significant progress in methanol-fueled vehicle commercialization. In 2017, according to China Nitrogen Fertilizer Industry Association (CNFIA), methanol consumption in China increased to 69.5 Mt in 2017.[52] Methanol derivatives, namely, dimethyl ether (DME) and methyl *tert*-butyl ether (MTBE), accounted for around 25% of the total consumption in that year. China produces about 65% of global methanol. Apart from China, Israel, Italy, Japan, and South Korea also use methanol as fuel. Methanol is mixed with other fuels as a component or directly used as fuel in internal combustion (ICE) and other types of engines. In gasoline, the blending is in the form of MTBE and in diesel, the most common blending is fatty acid methyl esters (FAME).[53] In China, methanol is sold as blended fuel ranging from M5 to M100. In Europe, maximum 3% methanol by volume is allowed in gasoline under the European Committee of Standardization (CEN) directive EN 228 and fuel quality standard 2009/30/EC. In the United States, similar directives are regulated by the American Society for Testing and Materials (ASTM) that limit methanol blending to different fuel categories.[54] Methanol-blended gasoline emits lower carbon monoxide, hydrocarbons, and nitrogen oxide levels than pure gasoline emissions.[55] It was recently reported that in China's Guizhou province ∼5000 methanol-fueled taxis are in operation. This region alone accounts for 75% of the total methanol-fueled vehicles in the country. The government has also launched 13 methanol filling stations. India's methanol production capacity in 2022 is estimated at 2 Mt per annum. This production capacity is expected to increase annually by up to 20 Mt by 2025.[56]

The marine industry is seeing methanol-based fuels as an opportunity for the future.[24,57] It is also expected to grow due to increasing demand from the construction, automotive, and personal care industries. Used in sewage treatment plants, methanol acts as a carbon-based food source for denitrifying bacteria.[58] It is also used as antifreeze to lower the freezing point of a liquid in pipelines.[59] The major methanol producers worldwide are Methanex, Sabic, Methanol Holdings (Trinidad) Ltd., LyondellBasell Industries Holdings, and Petronas, among others. Methanol-based components, like formaldehyde, dominated the market in 2018. For the years between 2019 and 2024, the global methanol market is expected to have a combined annual growth rate (CAGR) of 5.64%.[52,60] Among other factors, increased demand for methanol-based fuels drives the market. Health and safety issues stemming from methanol's hazardous effects are expected to partly hinder market growth.

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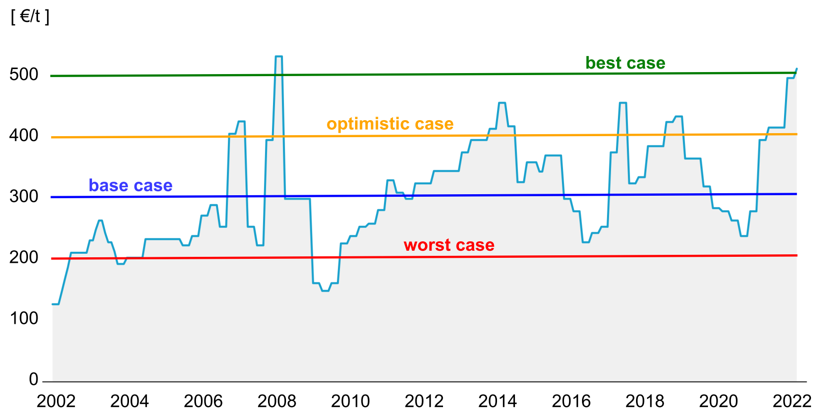

Figure 3. 20-year historical methanol market price between January 2002 and January 2022.[51] Four price bands—best, optimistic, base, and worst case—are used for modeling different scenarios.

Having looked at the market, let us briefly address some of the economic factors driving methanol production costs. To this end, it is pertinent to evaluate the impact of regulatory, economic, and market factors on producing renewable methanol using industrial carbon emissions. These factors pose substantial challenges and are not properly addressed in published works. For example, hydrogen market conditions are still evolving, making it difficult to make economic decisions about renewable methanol production using procured hydrogen at market prices. Furthermore, it is difficult to call the produced methanol as carbon-neutral or net-zero if we cannot be sure about the underlying hydrogen production process. As of 2022, green hydrogen is about 2−3 times more expensive than blue hydrogen produced from fossil fuels through CCS. The production cost of green hydrogen depends mainly on the price of renewable electricity and the capital and operating costs of the water electrolyzer. In many regions of Europe, the cheapest levelized cost of energy (LCOE) from new wind and solar installations is around 40−50€/MWh. At this price level, we are still not very cost competitive. However, experts believe that price levels will be significantly reduced in the coming years.[61] While cheap carbon-free electricity is a necessary prerequisite for competitive green hydrogen, electrolyzers capital investment costs must also drop substantially.

From the regulatory standpoint, I believe that regions should set very clear rules for competition between different types of fuels and technologies based on a comparable life cycle analysis (LCA) and comprehensive energy supply security considerations.[62] Renewable methanol as a fuel requires robust renewable fuel-focused policies. Various efforts including government mandates for fuel blending quotas, renewable fuel incentives, and carbon emission taxes would impact the market's willingness to pay a premium for renewable methanol. If and when such a regulatory and policy push is made, recycling industrial carbon emissions will become an increasingly viable option available to us to create a net-zero fuel strategy. As we move toward a net-zero society, we must embrace carbon dioxide, especially emitted by industry, as invaluable future feedstock for renewable fuel and value-added material production. That being said, we need to improve various technoeconomic factors of CCU solutions for this to happen.

First, we need to reduce the overall cost of carbon capture, purification, and transport to a competitive level. In our assessment, I have not factored in this cost. Based on real examples, I have considered that the methanol production unit is next to a heavy industry, waste to energy or other fossil-fuel-driven manufacturing plant where emissions are directly captured, purified, and transported through dedicated pipelines to the nearby methanol synthesis unit. But if capture infrastructure is not already in place, we need to incorporate this CO_2 capture, purification, and transport cost into the calculation. Carbon capture costs vary significantly based on the industrial source of CO_2. For example, ethanol production or natural gas processing produce highly concentrated CO_2, whereas cement production and power generation processes produce less concentrated carbon emissions. Current estimates per tonne of captured CO_2 range from \$15 to \$25 for highly concentrated industrial CO_2 streams to \$40−\$120 for less concentrated CO_2 emissions.[63]

Second, the process for producing methanol from CO_2 also needs to be improved taking into account the overall environmental and energy balance. For this, we need sustained investment in research and development. For such investments, the industry and investors require assurance from policy-makers regarding CCU and net-zero carbon fuels. This can be in the form of subsidies, grants, public−private partnerships for developing CCU solutions, and encouraging CCU-derived net-zero fuels. By providing such regulatory support, investors will be encouraged to invest in renewable methanol derived through CCU pathways.

Special regulatory, market, and economic circumstances have led to realistic methanol production opportunities. For example, in Iceland, where electricity prices are very low, methanol is currently being produced from CO_2 at a competitive price compared to gasoline. To replicate such a scenario elsewhere, we need to lower the overall cost of synthesizing renewable methanol from CO_2. The main factor driving this is electricity costs. Another key factor is the proximity of the source of CO_2 emissions to the place where hydrogen and methanol will be produced. When they are far apart, the cost of transporting raw materials will be high. In Iceland, electricity is generated cheaply from geothermal energy and the raw material, namely, CO_2, is available in abundance from geothermal sources.

I strongly believe that renewable methanol production from industrial emissions will be an invaluable model for the circular economy. This is built on a symbiotic ecosystem integrating various actors in the emission-to-methanol supply- and value chain. In our assessment, I will take these factors into consideration while studying the technoeconomic sustainability of an integrated renewable methanol production ecosystem that

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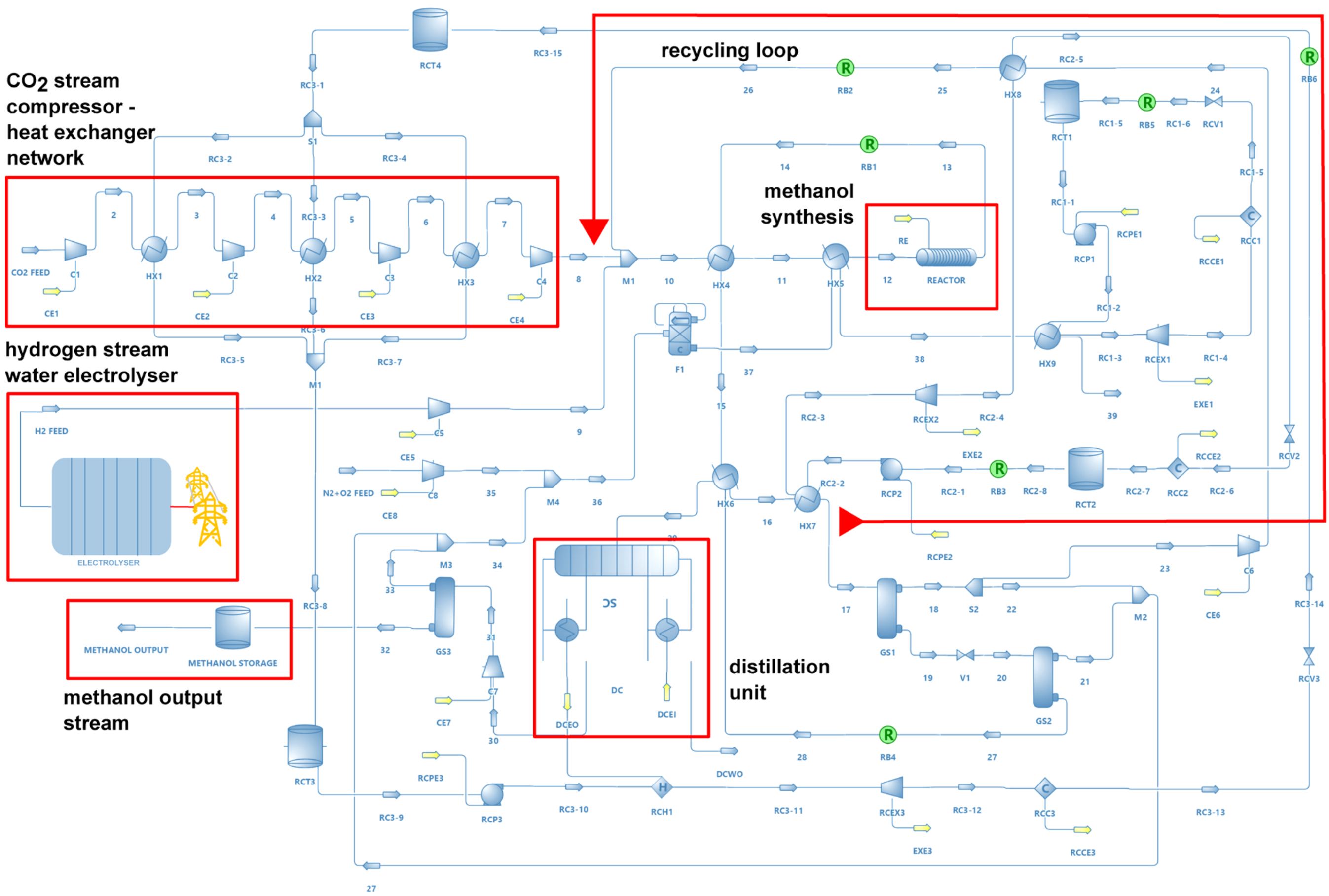

Figure 4. Blueprint of the integrated hydrogen and methanol production plant using industrial carbon emission input.

includes a hydrogen production unit powered by carbon-free electricity.

INTEGRATED HYDROGEN AND METHANOL PRODUCTION ECOSYSTEM

I have designed an integrated hydrogen and methanol production ecosystem for two production capacities. Compared to previous works, our modeling evaluates the feasibility of producing methanol under realistic market, economic, and regulatory conditions emphasizing the importance of the overall supply- and value-chain integration of stakeholders such as industries producing carbon emissions, electricity producers, buyers of methanol, and byproduct oxygen.

I have considered two production ecosystems, namely, a large-scale plant (LSP) and a very large-scale plant (VLSP), for our analyses. I have provided a high-level blueprint of the integrated hydrogen and methanol production ecosystem in Figure 4. Both LSP and VLSP follow the same blueprint. The differences between these two plants, however, are only in the ratings and capacities of each component for handling different input levels of CO_2 and different production capacities for hydrogen and methanol. VLSP is assumed to be 10 times LSP's production capacity. I have designed LSP to handle 60 kilo tonnes per annum [kt/a] input of industrial CO_2 emissions. The overall LSP ecosystem incorporates an integrated hydrogen production unit using water electrolysis to supply 8.2 kt/a of hydrogen required to synthesize roughly 44 kt/a of methanol. On the other hand, VLSP is designed for 600 kt/a of CO_2 input incorporating 82 kt/a hydrogen production unit to synthesize roughly 436 kt/a of methanol. The blueprint highlights the main components of the plants, namely, compressor—heat exchanger network of the input CO_2 stream, water electrolysis-based hydrogen production unit, methanol synthesis unit, recycling loop, distillation unit, and methanol output stream. The methanol synthesis unit is based on heterogeneous catalytic (electro)chemical reactions.[64,65] The complete steady-state process flow modeling was designed, implemented, and optimized using DWSIM.[66]

There are several tools available for process simulation and modeling in CCU, including commercial software such as Aspen Plus, Aspen HYSYS, and CHEMCAD. However, I have chosen DWSIM for this CCU case study due to its comprehensive features, open-source nature, user-friendly interface, and advanced analysis capabilities, which have provided me with the necessary flexibility and efficiency in modeling CCU processes. Being open-source software, users can easily modify, expand, and adapt simulations to suit their specific requirements. This, I strongly believe, encourages collaboration and innovation within the CCU community. Users can actively contribute to its development, suggest improvements, and customize the software to their specific needs. I modeled and simulated individual processes to understand their capabilities and performance. I later used these insights to synthesize the overall CCU system design and operation including the integrated hydrogen production unit. I also used sensitivity analysis to evaluate CCU processes' performance and efficiency. These features enable users to identify key parameters, perform scenario analyses, and optimize process conditions. This, I

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strongly believe, is imperative to enhance our integrated CCU system's economic and environmental viability.

Technoeconomic Parameters of LSP and VLSP. Before delving into the economic assessment of these two integrated hydrogen and methanol production plants, I would like to briefly highlight the technoeconomic parameters of the modeled LSP and VLSP. In Table 3, I have detailed the main technoeconomic parameters of our plant design for LSP and VLSP. Our plant design is based on calculations using DWSIM modeling.[66] Production economics related to CAPEX and OPEX are based on 2020−2021 cost levels in the EU market zone.

Table 3. Important Technoeconomic Parameters of LSP and VLSP

parameters	LSP	VLSP
mass balance [t/t_{CH_3OH}]		
inlet CO_2	1.38	1.38
inlet hydrogen	0.19	0.19
outlet methanol	1.00	1.00
outlet water	0.56	0.56
CO_2 reactor conversion rate %	43.51	33.80
CO_2 process conversion rate %	96.00	93.00
gross CO_2 converted [t/t_{CH_3OH}]	1.32	1.28
net CO_2 converted [t/t_{CH_3OH}]	1.16	1.16
energy balance [MWh/t_{CH_3OH}]		
electricity consumption	9.58	9.52
cooling energy consumption	1.47	1.16
net compressor power rating [MW]	1.13	10.16
net pump power rating [MW]	0.01	0.12
net turbine power rating [MW]	1.27	14.69
net cooler power rating [MW]	8.00	63.00
production economics [€/t_{CH_3OH}/a]		
CAPEX	954.29	751.32
variable OPEX	650.89	567.94
fixed OPEX	45.31	22.00

I shall now explore the economic aspects of these two integrated hydrogen and methanol production ecosystems. Our aim is to derive preliminary estimates (with ±30−40% accuracy) for capital expenditure (CAPEX), operational expenditure (OPEX), and revenue streams for a greenfield production setup.

Economics of an Integrated Production Ecosystem. Before delving into the specifics of LSP and VLSP, let us briefly highlight the different costs included in the CAPEX and OPEX calculations and different revenue streams considered. For CAPEX, I have initially calculated the cost of delivered equipment and used this to compute the overall CAPEX as a percentage of purchased equipment cost.[67] I would like to remark that finding the actual prices of delivered equipment in a specific case is a big challenge. This is because actual prices of delivered equipment depend on factors such as the place and time of delivery, sizes and specifications of the equipment, pricing currency, technology, service guarantees, manufacturer, etc. Most of the earlier efforts calculated purchase equipment costs based on the *capacity scaling* approach. In my opinion, the capacity scaling method could be misleading if we lack confidence in the original prices and if the scaling extends beyond 10 times the original capacity for which prices are known.

To avoid this challenge, for our integrated hydrogen and methanol production ecosystem, I have calculated the overall purchase equipment costs for different plant capacities. As part of our due diligence process, I collected actual project costs from different past purchases. Whenever such information is not available for a specific equipment size, I have resorted to the capacity scaling method to find the relevant costs. In doing so, I have exercised caution so that our scaling is within the range where the method is still reasonably accurate for getting the preliminary estimate.

It should be noted that building, yard improvements, and land-related costs are relevant for greenfield projects where land must be newly acquired. However, for brownfield projects or expansion projects where land and buildings are already available, these costs can be neglected. I have assumed a greenfield project where all of these factors will be taken into account. Direct and indirect plant costs included in the CAPEX calculation are given in Table 4.

Table 4. Direct and Indirect CAPEX Costs

direct costs	indirect costs
purchased equipment cost (delivered)	engineering and supervision
purchased equipment installation	construction expenses
instrumentation and controls (installed)	legal expenses
piping (installed)	contractor's fee
electrical system (installed)	contingency
buildings (including services)	
yard improvements	
land	

Now let us briefly look at the OPEX calculation, which includes fixed and variable operational and maintenance costs (O&M) as indicated in Table 5.

Table 5. Fixed and Variable CAPEX Costs

fixed OPEX	variable OPEX
labor costs	water
general overhead	electricity
annual O&M	catalysts
insurance	other variable costs
local taxes and fees	

The main source of revenue from plant operation comes from methanol sales. However, there are also two other potential secondary revenue streams: carbon emission credits and byproduct sales (oxygen from water electrolysis). It is also worth mentioning that there is a small amount of electricity generated using steam turbines utilizing excess heat from the exothermic methanol production process. However, this electricity is considerably less than the overall electricity consumed in water electrolysis. Hence, I have not considered any sale of generated electricity in the scenarios presented in the paper.

Finally, I have assumed that the overall CAPEX will be distributed over years 1, 2, and 3 of plant construction at 30, 60, and 10%, respectively. Thus, production is planned to start at 30% of full capacity in year 3. It will then gradually increase to 70 and 100% of full capacity in years 4 and 5.

CAPEX and OPEX for LSP and VLSP. Taking into consideration the above factors, I have calculated the overall CAPEX required to implement LSP and VLSP. The CAPEX

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values calculated for these two plant capacities along with details of annual CO_2 utilized, H_2 and O_2 produced via water electrolysis, and methanol synthesized are given in Table 6.

Table 6. CAPEX of LSP and VLSP along with Input and Output Streams

parameters	LSP	VLSP
Materials [kt/a]		
utilized CO_2	60	600
produced H_2	8.2	81.8
Outputs [kt/a]		
main product CH_3OH	43.6	436.3
byproduct O_2	65.4	654.5
CAPEX [M€]		
direct costs	34.6	286.5
indirect costs	7.1	41.3
total	41.7	327.8

These preliminary estimates for CAPEX will set the basis for doing scenario analyses taking into account assumptions for OPEX parameters. I will now elaborate on the OPEX and revenue assumptions for a detailed economic feasibility assessment. In our operational cost consideration, I have set the base case prices for electricity as 50€/MWh, water as 0.25€/m^3, and catalyst as 95€/kg. LSP and VLSP labor costs are computed with 12 and 18 full-time equivalent (FTE) employees, typical for plants of this size. A critical factor in the overall economic feasibility of these plants will be the carbon-free electricity price. In Table 7, I have given the OPEX values assumed for LSP and VLSP for the base case scenario.

Table 7. Cost Components of OPEX of LSP and VLSP for Base Case Assumptions for Raw Materials and Labor

OPEX [M€]	LSP	VLSP
electricity	20.9	207.7
water	4.1	33.0
catalyst	3.4	7.1
total variable OPEX	28.4	247.8
labor	0.7	1.1
overhead	0.2	0.3
annual (O&M)	0.6	4.9
insurance	0.2	1.6
local taxes and fees	0.2	1.6
fixed OPEX	2.0	9.6
total OPEX	30.4	257.4

To determine the base case for cost calculation, I first selected a reference capacity for the CCU plant. I collected cost data for the reference capacity, including OPEX and CAPEX. Next, I established scaling factors that related the reference capacity to the desired plant capacity. I applied these scaling factors to estimate OPEX and CAPEX for the desired capacity. I took into account equipment size, material quantities, labor requirements, and utilities consumption. I adjusted the estimated costs for inflation and currency exchange rates when necessary. To validate and refine the estimates, I compared them with historical data, industry benchmarks, and expert knowledge. It is pertinent to note that the capacity scaling method provides rough estimates, and actual costs may vary based on project-specific factors. Therefore, I recommend conducting further engineering studies and cost analyses as the project progresses.

I will now use these base case values for CAPEX and OPEX in detailed feasibility assessments of realistic scenarios.

RESULTS: SCENARIO MODELING

I have analyzed 32 realistic scenarios based on different economic, market, and regulatory assumptions for LSP and VLSP. Economic and market assumptions relate to guaranteed price levels for electricity, methanol, and oxygen (byproduct). While the former directly affects the variable OPEX, the latter two contribute to the revenue stream generated by the plants' operation. The regulatory factor relates to the enforceability of carbon credits for industrial polluters emitting greenhouse gases (GHGs). In many countries, carbon credits are not yet in place, so they do not contribute to cash flow. I have examined the net present value (NPV) of both plants using these 32 scenarios with different combinations of market, economic, and regulatory assumptions. I will only consider those scenarios for which we get positive NPV during the 20-year lifetime of both LSP and VLSP. In the context of a CCU project, a positive NPV signifies that the projected earnings from the project, after adjusting for the time value of money, surpass the expected costs, even when considering present-day values. A positive NPV suggests that the investment has the potential to be financially lucrative.

Ideally, a project should reach a positive NPV within a reasonable time frame. A project that takes too long to achieve a positive NPV may indicate potential challenges or risks in terms of profitability and return on investment. It can impact the project's attractiveness to investors and financiers. A longer time frame to reach a positive NPV may be problematic for several reasons given below.

- Time value of money: NPV takes into account the time value of money, which means future cash flows are discounted to their present value. The longer it takes for a project to generate positive cash flows, the greater the discounting effect and potential loss of value over time.
- Opportunity cost: A project with a long payback period may tie up financial resources for an extended period, limiting opportunities for alternative investments that could yield higher returns in a shorter time frame.
- Uncertainty and risk: Long-term projects are typically associated with higher uncertainty and risks, including changes in market conditions, technological advancements, regulatory frameworks, and environmental factors. These uncertainties can impact the accuracy of cash flow projections and the overall profitability of the project.

However, it is imperative to consider the specific characteristics and objectives of each investment case. In the case of CCU projects like ours, which have longer development cycles or strategic significance, we may have inherent reasons for taking an extended time to reach a positive NPV. In such cases, it becomes crucial to carefully assess and mitigate the associated risks and ensure that the project's long-term viability and benefits outweigh the extended timeline. The outcomes of our NPV assessment for LSP and VLSP are shown in Tables 8 and 9, respectively.

For LSP, only scenario S32 results in positive NPV, which is a best-case scenario as highlighted in Table 8. The LSP plant can only be economically sustainable when the market price for methanol stays minimum at 500€/t and the electricity price is guaranteed at 30€/MWh or less. Furthermore, this S32 scenario also requires an additional source of revenue from carbon emission credit at minimum 50€/t and oxygen sale at minimum

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ACS Omega 2023, 8, 29189−29201

Table 8. Feasibility Assessment of 32 Scenarios (Denoted as S01−S32) for LSP with Different Conditions for Electricity and Methanol Prices with and without Additional Revenue Streams from Carbon Credit and Byproduct (Oxygen) Sales[a]

CO_2 [€/t]	O_2 [€/t]	electricity [€/MWh]	scenario feasibility			
50	40	30	S29 X	S30 X	S31 X	S32 ✓
0	40	30	S25 X	S26 X	S27 X	S28 X
50	0	30	S21 X	S22 X	S23 X	S24 X
0	0	30	S17 X	S18 X	S19 X	S20 X
50	40	40	S13 X	S14 X	S15 X	S16 X
0	40	40	S09 X	S10 X	S11 X	S12 X
50	0	40	S05 X	S06 X	S07 X	S08 X
0	0	40	S01 X	S02 X	S03 X	S04 X
			worst case	baseline	optimistic	best case
		methanol [€/t]	200	300	400	500

[a]Only those scenarios where the plant NPV becomes positive within a 20-year period are highlighted in green.

Table 9. Feasibility Assessment of 32 Scenarios for VLSP (Denoted S01−S32) with Different Conditions for Electricity and Methanol Prices with and without Additional Revenue Streams from Carbon Credit and Byproduct (Oxygen) Sales[a]

CO_2 [€/t]	O_2 [€/t]	electricity [€/MWh]	scenario feasibility			
50	40	30	S29 X	S30 X	S31 ✓	S32 ✓
0	40	30	S25 X	S26 X	S27 X	S28 ✓
50	0	30	S21 X	S22 X	S23 X	S24 ✓
0	0	30	S17 X	S18 X	S19 X	S20 ✓
50	40	40	S13 X	S14 X	S15 X	S16 ✓
0	40	40	S09 X	S10 X	S11 X	S12 X
50	0	40	S05 X	S06 X	S07 X	S08 X
0	0	40	S01 X	S02 X	S03 X	S04 X
			worst case	baseline	optimistic	best case
		methanol [€/t]	200	300	400	500

[a]Only those scenarios where the plant NPV becomes positive within a 20-year period are highlighted in green.

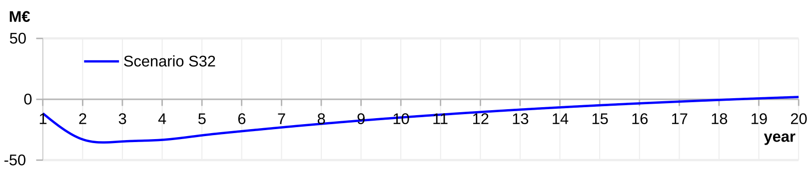

Figure 5. Positive NPV scenario for LSP defined in Table 8.

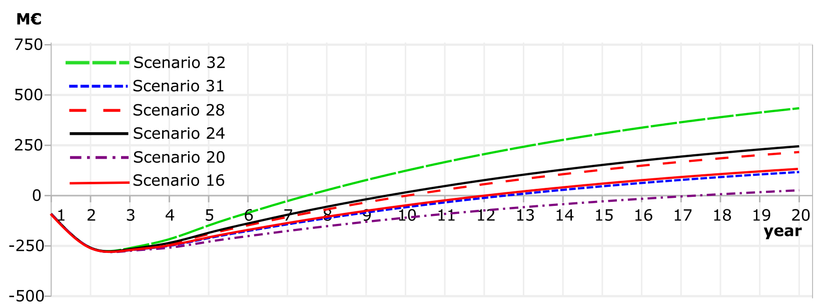

Figure 6. Positive NPV scenarios for VLSP defined in Table 9.

40€/t. It should be further remarked that even with this scenario S32, the LSP will take about 18 years to reach a positive NPV as shown in Figure 5.

In the case of VLSP, six scenarios, namely, S16, S20, S24, S28, S31, and S32, result in positive NPV as highlighted in Table 9. As shown in Figure 6, all six scenarios will reach a positive NPV in a

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ACS Omega 2023, 8, 29189−29201

shorter time period than the previous LSP case. For VLSP, only scenario S31 leads to positive NPV with an optimistic price level of methanol at 400€/t. However, this scenario requires electricity cost to be maximum 30€/MWh along with additional revenue from carbon credit and oxygen sale at minimum 50 and 40€/t, respectively. In scenario S20, VLSP requires methanol selling price to be at least 500€/t, electricity at most 30€/MWh without any additional revenue from carbon emission credit and oxygen sale. Scenario S24 is the same as S20 but with carbon credit at least 50€/t. Scenario S28 is the same as scenario S20 but with oxygen sales at least 40€/t. Finally, scenarios S32 and S16 for VLSP differ only in electricity prices. Scenario S32 requires the maximum price of electricity to be 30€/MWh; however, scenario S16 allows the price of electricity to be up to 40€/MWh. Both these scenarios require methanol price to be at least 500€/t and additional revenue from carbon credit and oxygen sale to be at least 50 and 40€/t, respectively.

I have compared our LSP and VLSP production economics with previously published results based on the source of carbon, annual production capacity (APC), CAPEX, and OPEX per APC. The results are shown in Table 10 along with respective references.

Table 10. Comparison of Annual Capacity, CAPEX, and OPEX per Tonne of Present Work (LSP and VLSP) with Previously Published Work[a]

carbon source	annual capacity [kt/a]	CAPEX per tonne [$/t]	OPEX per tonne [$/t]	reference
biogas/ammonia	4−10	1680−4700	510−1270	43
unknown	16.3	980	840	68
flue gas (electricity €30/MWh)	43.6	1088	575	this work LSP
flue gas (electricity €40/MWh)	43.6	1088	684	this work LSP
flue gas	50	1900	220−770	69
CPP flue gas	60−120	1640−3010	230−300	39
flue gas	100	620	880	42
CPP flue gas	300	1150	540	70
flue gas (electricity €30/MWh)	436.3	857	455	this work VLSP
flue gas (electricity €40/MWh)	436.3	857	564	this work VLSP
CPP flue gas	440	1260	740	41
flue gas	1800	235	420−922	71

[a]An exchange rate of 1€ = $1.14 and zero carbon credit have been considered.

For our LSP and VLSP, I have considered two different unit electricity prices influencing the OPEX per APC. Cheap electricity substantially increases our methanol production ecosystem's financial viability. Hence, it is imperative to develop long-term firm agreements for raw material prices engaging different stakeholders. This is discussed further in the next section.

DISCUSSIONS: KEY TAKEAWAYS

From the above 32 scenario analyses, I can draw some major conclusions. Methanol and electricity prices significantly impact plant economic sustainability. If the methanol price is below 500€/t, there are no viable scenarios for LSP. Methanol plants with an installed capacity comparable to LSP or less need solid support in the form of carbon emission credits, additional revenue from oxygen sales, and guarantees of electricity supply at a maximum of 30€/MWh. These are very tight market conditions, which can only be achieved through long-term strategic partnerships with actors in the emission-to-methanol supply- and value chain. Large methanol plants like VLSP can be viable even when methanol is priced at 400€/t, provided carbon emission credit and oxygen sales are guaranteed at least 50 and 40€/t, respectively. When the methanol price increases to 500€/t or more, VLSP can be commercially sustainable even without carbon emission credit and oxygen sales. This is provided carbon-free electricity stays at or below 40€/MWh.

In sum, the following are critical insights and key takeaways from this study:

- Market sensitivity: The analysis underscores the sensitivity of CCU plant economics to market conditions, particularly methanol and electricity prices. Fluctuations in these prices can significantly impact the plant's feasibility and profitability. It is essential to closely monitor market dynamics and anticipate potential price variations to mitigate risks and optimize project outcomes.
- Regulatory support: The findings emphasize the importance of regulatory support, such as carbon emission credits, in ensuring CCU plants' economic viability. Government policies that incentivize and reward carbon-neutral production can attract investments and foster sustainable methanol production from industrial emissions.
- Scale considerations: The results highlight the contrasting viability of different plant scales. While smaller plants may face significant challenges to become commercially sustainable, larger plants demonstrate more resilience. This insight suggests that scalability plays a significant role in the economic feasibility of CCU projects. Careful consideration should be given to plant size during the planning and decision-making stages as it directly impacts financial capital, which in turn relates to investor sentiments and expectations.
- Holistic approach: The study emphasizes the importance of a holistic approach when evaluating CCU plants' commercial sustainability. Factors beyond methanol and electricity prices, such as additional revenue streams from oxygen sales and value-chain strategic partnerships, are crucial to ensuring long-term viability. A comprehensive analysis that incorporates various elements of the value chain will provide a more accurate assessment of project feasibility.

By considering the above critical insights and takeaways, stakeholders can better navigate CCU plant projects successfully. They can also make informed decisions to maximize the economic and environmental benefits of methanol production from industrial carbon emissions. In the following, we will further elaborate and discuss supply- and value-chain integration aspects.

Supply- and Value-Chain Integration. Circular economy models are often seen as progressive. However, they often become part of a wishful thinking process if we do not pay proper attention to the entire supply- and value chain in which they operate.[49,72,73] In this section, I will briefly discuss the importance of supply- and value-chain integration required for creating an economically sustainable circular economy model to transform industrial carbon emissions into methanol. As I have

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shown in the earlier sections, the cost of electricity and the price of renewable methanol play a significant role in the overall economic sustainability of the integrated production ecosystem. This requires bringing together four groups of stakeholders, namely,

- industrial CO_2 emitters,
- carbon-free electricity producers (utilities),
- integrated methanol and hydrogen production plant operators, and
- different industrial end-users of methanol and oxygen.

The first two groups of stakeholders are resource suppliers, namely, carbon dioxide and electricity. The last stakeholder group represents industrial consumers of methanol and oxygen. It is vital to develop long-term strategic agreements with industries that emit CO_2, ideally with carbon emission credits, if local and regional regulations support and favor carbon emission taxation. Firm-agreement with utilities with a long-term guarantee for electricity price is fundamental to secure cash flow and financial sustainability of renewable methanol plants. Utilities having spare carbon-free electricity capacity during off-peak hours can use methanol as a medium- and long-term storage medium at highly competitive prices compared to capital-intensive electric battery storage infrastructure. Long-term purchase agreements with different industrial end-user groups by fixing methanol and oxygen prices can ensure a steady flow of revenue as estimated in the positive NPV scenarios discussed in the previous section.

There are several end-user groups in the local and regional markets for methanol and oxygen. Presently, the major consumers of methanol are wastewater treatment plants, airports, pharmaceuticals, manufacturers of adhesives, foams, synthetic fibers, films, high-performance plastics, plywood, etc. In industries, oxygen is extensively used in steel-making, metal refining, and fabrication processes. Pharmaceuticals, petrochemicals, glass, ceramics, pulp and paper, and effluent treatment plants require oxygen for their processes. These end-users in local and regional European markets demand methanol and oxygen annually.

As part of this case study, I have investigated the potential for building long-term purchase agreements with some of the major end-users who can benefit from a guaranteed purchase price and quantity of methanol. This helps both methanol producers and end-user industries to accurately plan operations, budget, and cash flow with reduced uncertainties compared to open market conditions.

Most previous studies on methanol production considered unrealistic price levels in the range of 550−900€/t to justify its commercial viability. Some of them have shown that methanol production is a profitable venture based on these unrealistic assumptions. Our economic assessments show that methanol production under current price levels and regulatory conditions is fraught with practical difficulties. This could become a dead-end strategy for many investors. However, under certain market, economic, and regulatory conditions, it could be a sustainable strategy. To create this way forward, we need to reduce market uncertainties and create strategic partnerships with different stakeholder groups. Progressive regulation and policy that favor net-zero methanol will greatly encourage more investments for research and development and the successful deployment of CCU-based production ecosystems.

For producing large volumes of methanol, we require huge CAPEX and OPEX as in VLSP. Ideally, these huge economic barriers can be resolved if end-users together with industries that emit CO_2 and utilities producing carbon-free electricity can coinvest in an integrated methanol production plant following a public−private (PPP) or private−private partnership model. In addition, this type of investment could also be considered as a strategy for big corporations to diversify their capital investments. I have listed below the benefits for different stakeholder groups while engaging in a coinvestment model for creating a circular economy of methanol from industrial carbon emissions.

1. Industrial CO_2 emitters
   - responsibly recycle CO_2 emissions with zero-to-low environmental impact and carbon footprint,
   - create revenue streams from emissions by (co-)investing in the integrated production plant, and
   - avoid or reduce potential carbon emissions tax.
2. Energy utilities
   - sell excess capacity of carbon-free electricity at a guaranteed price level,
   - sell renewable energy during maximum availability and minimum demand periods at a fixed unit-price,
   - use methanol as a medium to store excess renewable energy and grid capacity,
   - participate in value-creation from waste by (co-)investing in the production plant, and
   - purchase methanol produced at a favorable price to generate electricity on demand for stabilizing the grid—this is particularly useful for renewable utilities with irregular loads and power generation capabilities.
3. Methanol producers
   - sustainably create value-added materials from carbon emissions using principles of a circular and net-zero carbon economy,
   - supply the products to end-users, ideally using long-term purchase agreements at an agreed price, quantity, and quality, and
   - provide long-term energy storage options to carbon-free electricity producers in the form of methanol and support grid stabilization.
4. End-user industries
   - benefit from agreed methanol price and reduce market price variation-related risks,
   - procure locally or regionally and avoid import, freight, and other related charges, and related carbon emissions,
   - possibility to coinvest in the model to build strategic partnerships with methanol producers, and
   - support circular economy ecosystem.

The above model for public−private or private−private partnership for circular economy products is not widely studied. In this paper, I have just scratched the surface of this interesting domain. I have highlighted some relevant learnings about PPP in the context of CCU plants in the following.[49]

Strengthening CCU Projects through Public−Private Partnerships. PPPs will play a crucial role in enabling the development of large-scale investment projects in the area of decarbonization and renewable energy by leveraging the resources and risk-sharing capabilities of both the public and private sectors. Through PPPs, the private sector can finance and manage strategic assets in synthetic net-zero fuel production

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ACS Omega 2023, 8, 29189−29201

infrastructure, making ambitious projects economically viable. While PPPs often involve government funding, they also offer opportunities for the private sector to assume specific risks under negotiated contracts. However, when it comes to PPP models for producing synthetic methanol or other net-zero fuels from industrial carbon emissions, there is still a need for further research and development to address the key challenges highlighted below.

In PPPs, it is essential to reconsider the role of suppliers and contractors. While efforts have focused on reducing investor uncertainty and optimizing risk pricing for infrastructure as an asset class, the true cost of risk transferred from the public to the private sector should not be overlooked. Investors often transfer major risks associated with design, construction, maintenance, and operations to contractors involved in the project. Accurately estimating construction, maintenance, operation, and financing costs presents challenges, leading to uncertainties and various associated risks. Additionally, "unknown unknowns," such as unforeseen technological advancements, can introduce further uncertainties. These uncertainties highlight the need for continuous monitoring, adaptive strategies, and a flexible approach to infrastructure development. This ensures that PPPs are well-equipped to address evolving needs and emerging paradigms in the renewable energy sector.

Further research and development is also needed to advance the policy and regulatory frameworks for PPP-based production of renewable net-zero fuels, such as methanol. A key aspect of this development involves regulatory derisking, which aligns regulations with private investors' preferences. Close collaboration between companies and governments is essential to foster investments in net-zero green fuels. To stimulate domestic demand for renewable energy, including synthetic methanol, there may be a need to dismantle vertically integrated, state-owned utilities. Additionally, monetary derisking measures, such as ensuring government or private green bonds' liquidity, can attract institutional investors. Currency derisking strategies protect foreign investors from local currency fluctuations. For low-income countries with limited capital markets, PPPs serve as a fiscal derisking mechanism. These are some of the key aspects to consider while building a CCU plant. More detailed assessments of such PPP models for developing net-zero fuel production ecosystems will be discussed elsewhere.

■ CONCLUSIONS

I have presented a comprehensive technoeconomic assessment of integrated hydrogen and methanol production, considering realistic market and economic conditions. For commercially viable renewable methanol production from industrial emissions, I have demonstrated using scenario-based modeling why favorable economic, regulatory, and market conditions are essential. Collaboration along the supply- and value chain, as well as careful evaluation of plant size and market dynamics, is critical for establishing sustainable methanol production ecosystems. Contrary to previous studies, using realistic market and economic conditions for methanol production, I have critically evaluated 32 realistic scenarios for two plant capacities supported by net present value calculations. I have provided high-level blueprints for two production capacities detailing technical, operational, and financial parameters including CAPEX and OPEX. I strongly believe that CCU pathways are imperative in our battle against climate change and global warming. To create a commercially sustainable integrated methanol production ecosystem utilizing industrial emissions, however, we need highly favorable economic, regulatory, and market conditions. In addition, I have presented arguments on why one has to think through stakeholder cooperation and public–private partnerships to mitigate various project risks. Such risk mitigations are paramount to the commercial viability of CCU plants producing renewable methanol. I have emphasized the need for further research and development to advance the policy and regulatory frameworks for PPP-based production of renewable net-zero methanol. A key aspect of this development is regulatory derisking, which aligns regulations with the preferences of private investors. Hence, close collaboration between companies and governments is essential to foster investments in net-zero green fuels. Without such favorable conditions and stakeholder cooperation, I have shown why the circular economy of renewable methanol from industrial emissions will be a dead-end strategy in most cases. In sum, integrating actors in the emission-to-methanol supply- and value chain will be critical for establishing commercially sustainable renewable methanol production ecosystems.

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Notes

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■ ABBREVIATIONS

ASTM	American Society for Testing and Materials
Bt	billion tonne
CAGR	combined annual growth rate
CAPEX	capital expenditure
CCS	carbon capture and storage
CCU	carbon capture and utilization
CEN	European Committee of Standardization
CNFIA	China Nitrogen Fertilizer Industry Association
CPP	coal power plant
CH_3OH	methanol
CO_2	carbon dioxide
H_2	hydrogen
O_2	oxygen
DME	dimethyl ether
EPC	engineering, procurement, and construction
FAME	fatty acid methyl ether
FTE	full-time equivalent
GHG	greenhouse gas
ICE	internal combustion engine
kt	kilo tonne
LSP	large-scale plant
Mt	million tonne
MTBE	methyl tertiary-butyl ether
NPV	net present value
OPEX	operational expenditure

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ACS Omega 2023, 8, 29189−29201

PPP public−private partnership
ROI return on investment
VLSP very large-scale plant

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