

Towards the Use of Renewable Syngas for the Decarbonization of Industry

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In this article we analyze how syngas produced in a renewable way can replace fossil-fuel based syngas production and thereby play an essential role in the decarbonization of industry. We show that in essentially all industrial applications renewable H₂ and/or CO can replace syngas from fossil fuel feedstocks, and quantify the flows of these chemical building blocks required for the transformation of industry towards a net-zero emitting sector. We also undertake a techno-economic analysis, in which

we demonstrate that under specific assumptions for the learning rates of some of the key process components, renewable syngas can become cost-competitive with that produced from fossil fuels. Cost competitiveness, however, only materializes for four of the five routes when natural gas prices are at least around 3 €/GJ and carbon taxes increase from 90 €/tCO₂ today to 300 €/tCO₂ in 2050.

1. Introduction

In order to mitigate global climate change, a net-zero CO₂ emitting industry is necessary to align with the targets of the Paris Agreement.^[1] A challenge for the refinery and chemical industry is that fossil CO₂ is not only emitted as a result of the energy required for the industrial processes or as a byproduct of the chemical processes. A substantial share of the carbon is also contained in products. These industrial carbon-based products are often combusted or incinerated, or they eventually decompose, after their use and hence lead to CO₂ emissions. If at all these emissions are commonly attributed to other sectors, such as agriculture, transport, or waste treatment, but they really originate from industry.

A way to avoid these often mis-attributed or sometimes even un-accounted industrial CO₂ emissions from carbon-based products is to use carbon in a circular fashion.^[2,3] This can be realized by the use of biomass or, alternatively, atmospheric

CO₂ as chemical feedstock, for instance to produce syngas (or synthesis gas), which is a mixture of carbon monoxide (CO) and hydrogen (H₂). At present, syngas is predominantly employed as intermediate chemical building block in a variety of industrial processes. It is produced from fossil fuels such as coal, oil, and natural gas, in well-established production processes that are relatively efficient and low in costs. To enable a future in which circular carbon is used as feedstock for renewable syngas production, the costs of the corresponding processes will need to go down. Hence, cost analyses are needed to investigate how and when competitiveness can be reached of renewable syngas production methods against the conventional fossil fuel-based methods.

In this paper we present an overview of the current and future role of syngas in industry. We first discuss the current state of incumbent processes and applications. We next describe five alternative, potentially renewable, routes to produce syngas and perform a learning curve analysis to project the levelized cost of syngas production (LCOS) up to the year 2050. We also examine the influence of CO₂ taxation on the costs of syngas production methods. This analysis should enable policy makers and industrial stakeholders to shape investments and regulations into the right direction when considering these new value chains. A better understanding of the most important cost parameters for each process can help technology developers to focus on improving these aspects first.

2. Role of Syngas in Industry: Presence

Today, syngas is almost entirely produced from fossil resources. In Table 1 we list the main reaction mechanisms in the four processes currently in use to convert fossil fuels into syngas or pure CO. The fossil resources are converted to syngas by various processes, such as steam methane reforming (SMR), coal gasification (CG), partial oxidation (POX), and autothermal

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Table 1. Reaction equations reflecting the main processes to produce syngas from fossil fuels.

	Reaction	Reaction name	Process
Conventional routes	$C_xH_y + x H_2O \rightleftharpoons xCO + (x + \frac{1}{2}y) H_2$	Steam reforming	SMR, CG, ATR
	$C_xH_y + \frac{1}{2}x O_2 \rightarrow xCO + \frac{1}{2}y H_2$	Partial oxidation	CG, ATR, POX
	$CO + H_2O \rightleftharpoons CO_2 + H_2$	Water gas shift (WGS)	SMR, POX, ATR, CG
	$C + CO_2 \rightleftharpoons 2 CO$	Boudouard reaction	CG

reforming (ATR).^[4] In these processes, multiple reactions take place, as specified in Table 1.^[5–8] The product gases are utilized for several applications. For hydrogen production, all carbon is generally converted into CO₂ and released to the air to maximize the formation of H₂. Hydrogen is used in refining, ammonia production, and various other applications. CO is also used directly as reagent to, for instance, reduce iron oxide for steel production and as building block for acetic acid production. A mixture of CO and H₂ is, for example, applied in the Fischer-Tropsch process, hydroformylation reactions, and the synthesis of methanol and methane.

Figure 1 depicts a Sankey diagram for how the present use of syngas in industry relies entirely on H₂ and CO produced from fossil-fuel resources.^[9] The total global demand of syngas is difficult to clarify because syngas is generally used as intermediate in several industrial processes. We estimate that more than 31 EJ of syngas in various mixtures is annually produced. This quantity of syngas is used as intermediate in the production processes of fuels, chemicals, and materials. Nearly 12 EJ is applied as pure hydrogen.^[10] More than 15 EJ of syngas,

mainly CO from coal, is used for iron production.^[11] For the synthesis of products that contain carbon, such as methanol, methane, hydrocarbon fuels, oxo chemicals, and acetic acid, currently almost 4 EJ of syngas is used.^[12,13,14,6,15,16] Some syngas is generated from coal for electricity production in IGCC power plants and in total more than 6 EJ of energy is lost due to heat and waste flows.^[17]

3. Role of Syngas in Industry: Prospects

Figure 2 summarizes the pathways for the use of syngas as intermediate for the generation of a series of final products in industry. The traditional production routes are indicated that rely today essentially only on the use of fossil fuels as input resources, as well as the future possible alternatives that employ renewable feedstocks through a number of different processes.

The nearly 12 EJ of syngas that is applied as pure hydrogen can potentially be replaced by renewable hydrogen directly.

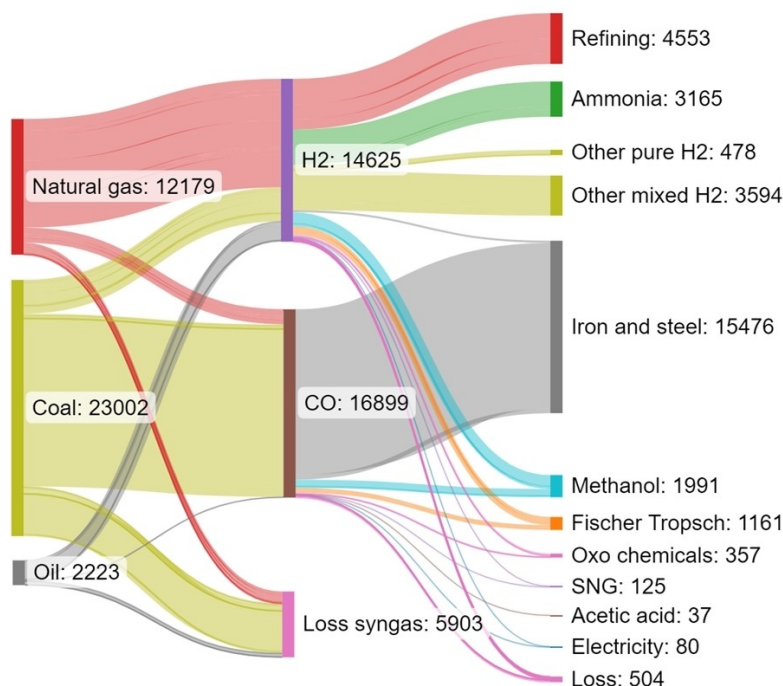


Figure 1. Sankey diagram for the current global use of syngas in industry. Values are given in PJ per year of energy stored in the product related to syngas (1 EJ = 1000 PJ).

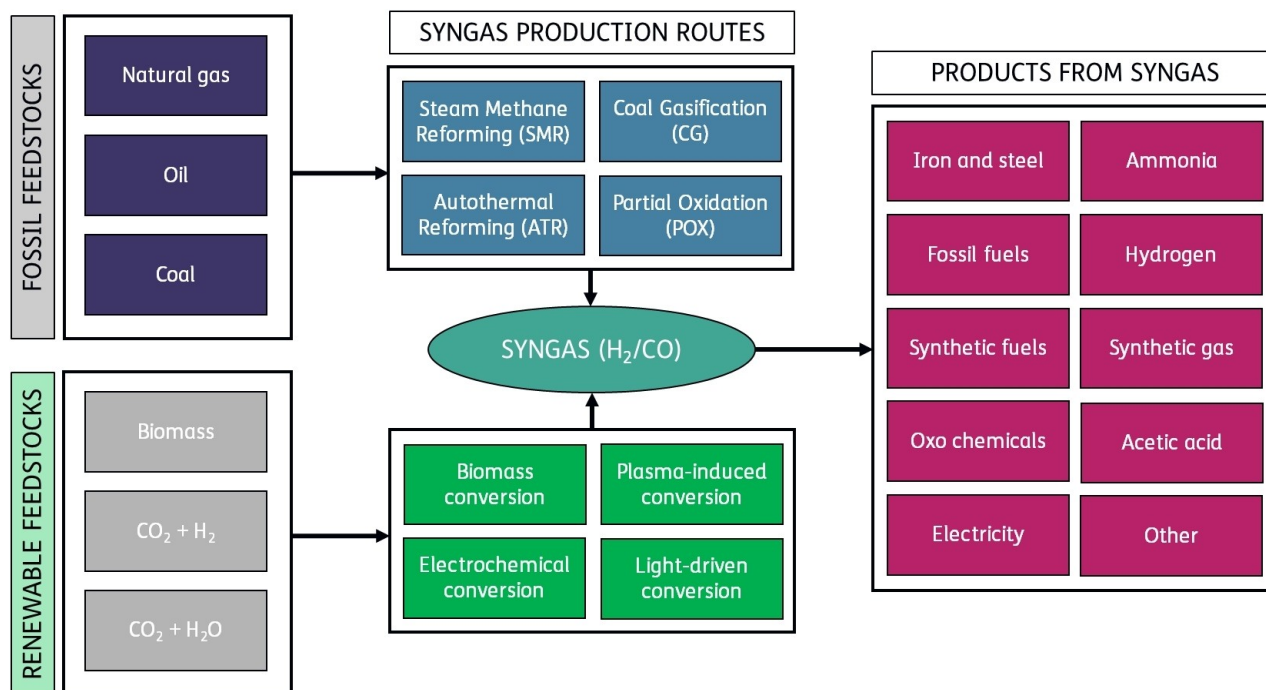


Figure 2. Pathways for syngas as intermediate for final products in industry: presence and prospects.

The more than 15 EJ of syngas for iron production is, despite that steel contains minor amounts of carbon, mainly used as reducing agent to convert iron oxide to iron metal. This process can potentially almost entirely be driven by electricity or hydrogen.^[10] Syngas usage to manufacture products that contain carbon, such as methanol, hydrocarbon fuels, oxo chemicals, SNG, and acetic acid are more likely to remain dependent on syngas as feedstock. As a first approximation of

the future market, we assume that demand for these carbon-based products will increase. Projections vary substantially, but here we assume that especially the market for methanol and Fischer-Tropsch (FT) fuels will increase to, respectively, 500 and 300 Mt (10 and 13 EJ) towards 2050.^[12,18,19] The production scale of oxo chemicals, SNG, and acetic acid is doubled in 2050 compared to 2020 data, together adding around 1 EJ to the total. Figure 3 depicts a Sankey diagram for how the future use

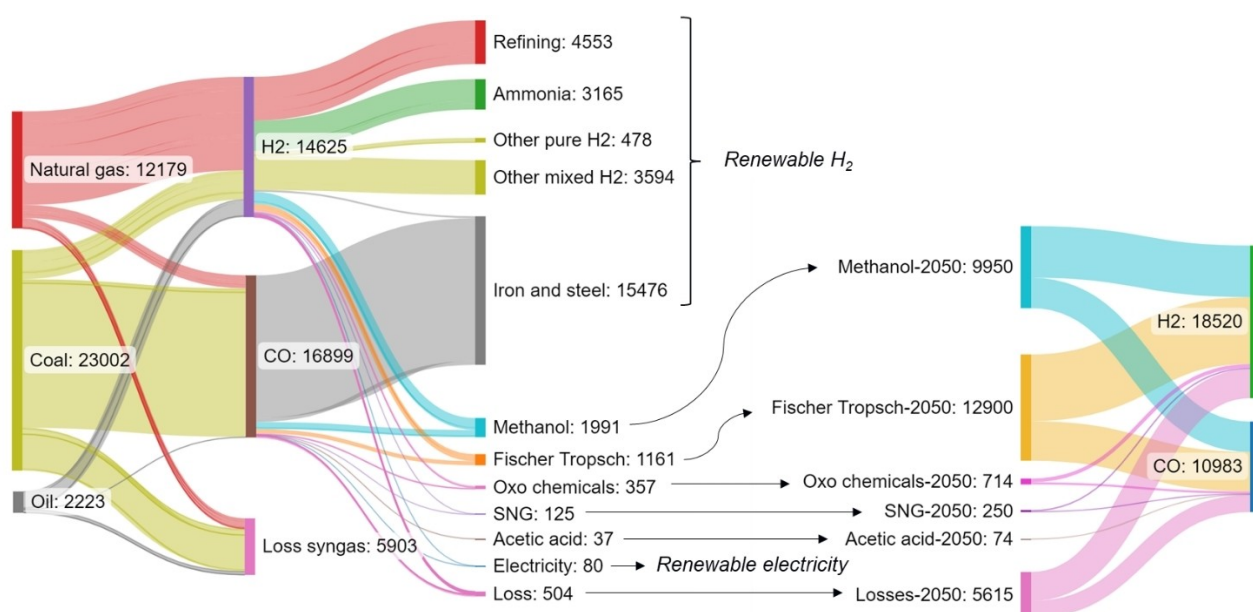


Figure 3. Sankey diagram for the future global use of syngas in industry. Values are given in PJ per year of energy stored in the product related to syngas.

of syngas in industry can rely entirely on H_2 and CO that are produced from non-fossil-fuel resources.

Methanol can be used to produce chemicals through the methanol to olefines (MTO) process, fuels through methanol to gasoline (MTG) and MTO/Mobil olefins to gasoline and distillate (MOGD) and FT synthesis can generate both fuels and naphtha, the latter being a starting material for chemicals production.^[20,21] Currently around 11 EJ (~255 Mt) of fuels for shipping and 10 EJ (~230 Mt) of aviation fuel is consumed in 2021.^[22] Additionally, around 23 EJ (~535 Mt) of hydrocarbons are used as petrochemical feedstock, mainly to produce chemicals and plastics. Together, these products amount to 44 EJ (1020 Mt) and a large share is expected to remain carbon-based and demand for these products is likely to increase in the future. Our projections indicate that in 2050 approximately 24 EJ of carbon-based products will be generated through syngas-based routes, i.e. these routes do likely not cover the total future demand.

In our scenario, 29 EJ of renewable syngas is required to supply 24 EJ of carbon-based products. We should note that such a demand in 2050 would require a cumulative annual growth rate of 46%, which is significantly higher as historically observed for the adoption of most technologies.^[23] It might help that several routes can produce renewable syngas, using different feedstocks and technologies. These routes exist of, for instance, biomass conversion processes, plasma-induced procedures, electrochemical methods, and light-driven approaches, amongst others. We here evaluate five routes within these categories. By this we envision how the approaches differ in efficiency, feedstocks, and costs. We also explore the future prospects of renewable syngas production by discussing the key dependencies and learning potential of the different routes.

3.1. Biomass Conversion

Biomass can be converted into syngas by applying different methods, such as biogas upgrading and reforming and biomass gasification, amongst others. The first is highly comparable to natural gas reforming, but uses biomethane as feedstock instead of natural gas. Here we only examine the latter, which is technically comparable to coal gasification. Different types of gasifiers can be applied for the conversion of biomass, they can be characterized as fixed bed, fluidized bed and entrained flow gasifiers. The fixed bed technology is most widely used,^[24,25,13] however mainly for heat and power applications and at small scale. Fluidized bed gasifiers are used for larger scale application and can deal with more complex feedstocks. Depending on the specific configuration the carbon conversion is between 95 and 100% and the gas composition resembles a syngas (but containing, next to CO and H_2 , considerable amounts of CO_2). Entrained flow gasifiers are commonly used for coal gasification and can be used for biomass as well, given sufficient adaptations. These gasifiers also operate at a nearly 100% carbon conversion efficiency. When biomass is used the technology readiness level would be at 8. Based on the IEA Bioenergy database,^[24] the total capacity of syngas production

from biomass and waste amounts to around 600 MW_{syn}. At an operational load of 8000 h, such capacity allows for an annual production of approximately 17 PJ of syngas, which, however, is only a fraction (0.06%) of our projected demand of 29 EJ of renewable syngas. This includes facilities that produce methanol, FT liquids, SNG, and electricity. The syngas generation from fossil resources entails a thermal capacity close to 200 GW_{syn}.^[24] Irrespective of the specific gasifier used, techno-economic analyses for a 300 MW_{syn} syngas production facility show that total specific investment costs range roughly between 600 and 2000 €(2020)/kW_{syn}.^[25,26] We assume that, for our base case, such a plant can go into operation for the average costs of 1300 €(2020)/kW_{syn} in 2028. To project costs up to 2050, we use a learning rate of 9%, which lies within the range of 7–10% that is reported for comparable biomass gasification technology.^[27,28]

3.2. Plasma-Induced Conversion of CO_2

Next to biomass as carbon source, other routes typically start from CO_2 as a circular carbon feedstock. CO_2 can, for instance, be converted into CO through non-thermal plasma CO_2 conversion technology. Addition of H_2 to the produced CO provides a syngas that is suitable for methanol production or FT synthesis. Several types of plasmas for CO_2 conversion are under development of which dielectric barrier discharges, microwave and gliding arc discharges are most common (Snoeckx & Bogaerts, 2017). Plasma CO production technology is not yet commercially available and only small prototypes have been developed (TRL 4–5) up to the kW scale. Here we focus on microwave plasma technology in which electricity is used to generate a plasma induced by microwaves. The single pass conversion of CO_2 to CO can be high but at the expense of energy efficiency and vice versa (Bogaerts & Centi, 2021). We here assume that the plasma process is operated at moderate energy efficiency (~50%) and CO yield (15%). Unreacted CO_2 is recycled in the process. Other process steps, such as cooling, compression, CO_2 absorption and regeneration, drying, and purification also consume energy, which results in an overall efficiency of 24%.^[29,30] Estimated costs for a plant with an annual capacity of 20 kton CO amount to 48 M€. After several development stages, we expect that such a sized facility (~17 MW_{syn}) can be deployed towards 2033 for specific investment costs of 2100–3500 €(2020)/kW_{syn}. Projected learning rates for this route vary from 10–20%, based on the learning rate of the microwave oven,^[31] of which we take 15% in our base case.^[30]

3.3. Electrochemical Conversion of CO_2 and Water

CO_2 can also be converted together with H_2O in an electrochemical process. We have analyzed several electrochemical conversion routes of which one to produce syngas.^[32] In this route, CO_2 and H_2O (steam) are co-electrolyzed at high temperature in a solid oxide electrolyzer (SOE) to produce O_2 and syngas. The co-electrolysis technology is still in the develop-

ment phase with an achieved TRL of 5 to 6. A 150 kW_e system has been developed that operates at around 850 °C, with electrolyte supported cells and stack technology.^[33] Demonstration of the technology at megawatt scale is currently ongoing in the MegaSyn project.^[34] The process proceeds with a nearly quantitative carbon conversion efficiency, although some remaining CO₂ has to be recycled. The total electricity input to produce a kg of syngas amounts to 8.1 kWh of which nearly 90% is consumed by the electrolysis process. The investment costs for a single MW_e system amount to roughly 3000–5400 EUR/kW_e or 3700–6600 €(2020)/kW_{syn} syngas output (Detz et al., 2023). We expect that these systems are market-ready in 2024 and that scale-up towards 100 MW_{syn} plants is realized in 2032. For 7000 full load hours (FLH) of operation, such a sized plant produces around 106 kton (2.5 PJ) of syngas a year. No learning rate for SOE has been reported and costs are typically projected based on the learning rate of solid oxide fuel cells (SOFC's).^[32] We use a learning rate of 20% and start from a cumulative installed capacity of 500 MW_e (of mainly SOFC's) or, at 82% efficiency, 410 MW_{syn}.^[32]

3.4. Light-Driven Conversion of CO₂ and Hydrogen

Besides biomass and renewable electricity, also sunlight can supply the energy to convert CO₂. Several options are explored, such as photocatalytic and photoelectrochemical conversion technologies, but here we focus on two routes more specifically: 1) sunlight-driven reverse water gas shift in which CO₂ and H₂ are converted in CO and H₂O, and 2) solar thermal conversion of CO₂ by metal oxide. The technology for sunlight-driven reverse water gas shift has already been demonstrated in the lab and pilot studies in relevant environment are underway (TRL 4–5).^[35–37] Unoptimized laboratory experiments indicate a solar efficiency of around 4% (Energy_{CO,out}/Energy_{light,in}). We have recently analyzed the techno-economics of the Au/TiO₂ catalyzed sunlight-driven process for a plant with a CO production scale of 100 kton/yr.^[38] CAPEX amounts to around 325 M€ for a base design, while a more developed process (operating at a higher throughput and efficiency) results in 51 M€ of investments. A similar plant design would have the capacity to generate 114 kton/yr (86 MW_{syn}) of syngas by adding 14 kton of H₂ to the in- and output flow of the process. Operation of this plant at 2000 full load hours (FLH), i.e. driven by sunlight, results in the production of 26 kton/yr (0.6 PJ/yr) of syngas. We here assume that towards 2035 a first-of-a-kind plant at such a scale can be realized for a specific CAPEX of 2200 €(2020)/kW_{syn} (around 190 M€) and operating at a single pass conversion yield of 18% and a solar efficiency of 46%. The performance of the process will be enhanced during development and scale-up but in our analysis these improvements are only represented by a reduction in specific CAPEX thanks to learning. The panel-type design could easily be scaled-up in numbers and would benefit from mass production manufacturing, similar to solar PV modules. For this reason we apply a learning rate of 24%, which is the reported LR for PV modules between 1976 and 2021.^[39]

3.5. Solar Heat Conversion of CO₂ and Water

In solar thermochemical conversion of CO₂ and H₂O approaches, a metal oxide redox cycle is driven by solar heat, typically at temperatures of 1500 °C or above. To reach these high temperatures, sunlight is concentrated with heliostats on the reactor that contains the metal oxide material, for example, Fe₃O₄ or CeO₂.^[40,41] The activated metal oxide subsequently reduces CO₂ and H₂O to syngas (CO and H₂). In this process, the metal oxide is oxidized again and ready for the next cycle. Mass and energy balances are derived from Falter et al.,^[40] only focusing on the syngas production step. Heliostats are already commercially used for concentrated solar power (CSP) generation but the technology to generate syngas is still at a prototype stage.^[42] Based on these insights, this route is determined at a TRL of 4–5.^[43] Investment costs are determined at 6350 €(2020)/kW_{syn} based on the average of two techno-economic assessments and scaled to a syngas production capacity of 132 kton/yr (or 100 MW_{syn}).^[40,41] We suppose that a facility for these costs and at such scale can be deployed in 2035, runs at 2500 FLH and produces 38 kton (0.9 PJ) of syngas per year. The energy efficiency of the process is determined at 10%. The selected learning rate of 18% is the average of the range of learning rates that is found for CSP generation.^[44] Cumulative capacity of CSP was 6.8 GW_e (corresponding to 4.5 GW_{syn} if we compare the efficiencies of electricity and syngas production of 15% and 10%, resp.) by the end of 2021.^[45] We expect that CSP for electricity and heat production is growing as well and because of that we increase the cumulative learning capacity for this route by 1000 GW in 2050.

4. Cost Analysis

The five different technology routes are each at their own development stage and cost level, as described in the previous sections. Some of the key parameters are also based on the specific plant capacity that is considered in the techno-economic studies, which we consulted (Table 2). The time that it takes to go through the different development stages and to reach a certain scale is accounted for with our market uptake parameter. The market uptake year indicates in which year a first-of-a-kind plant can be built at the capacity and specific investment costs as shown in Table 2. Throughout the entire deployment of the technology, the investment costs decline according to the technology learning curve, which initiates at a cumulative installed capacity in 2023 and follows a technology specific learning rate (Table 2). We have extrapolated the learning curve in two directions, starting from the reported specific investment costs in the market uptake year.

In our scenario, the five technology routes diffuse at different rates. We select these rates based on the TRL of the key technologies involved and determine the maximum plant size at 300 MW_{syn} syngas output, except for the SOEC process that can scale toward a 500 MW_{syn} plant-size. We assume that a technology at TRL 4/5 is demonstrated in 2020 at approximately 0.01 MW_{syn} capacity and that an order of magnitude scale-up

Table 2. Overview of key parameters of five renewable syngas production routes.

Route	Current TRL	Plant capacity ^[a] (MW _{syn})	Market uptake (year)	Specific investment costs (range) (€/kW _{syn})	Learning rate (%)	Cumulative installed capacity in 2023 (MW _{syn})
Biomass gasification	8–9	300	2028	1300 (600–2000)	9	200,000 ^[b]
Microwave-induced plasma CO ₂ conversion	4–5	17	2033	2800 (2100–3500)	15	0.1
Solid oxide electrolysis of CO ₂	5–6	1	2024	5100 (3700–6600)	20	410 ^[d]
Sunlight-driven reverse water gas shift	4–5	86	2035	2200 (600–3800)	24	0.1
Solar-thermal CO ₂ conversion	4–5	100	2035	6400 (5400–7300)	18	4,500 ^[d]

^[a] Capacity as analyzed in techno-economic studies (not the current status); market uptake and investments costs are related to this analyzed plant capacity. ^[b] Cumulative capacity and existing experience is based on installed coal gasification capacity. ^[c] Cumulative capacity and existing experience is based on solid oxide fuel cell and electrolysis capacity. ^[d] Cumulative capacity and existing experience is based on CSP capacity.

takes around 4 years until the maximum plant size is reached. We triple the amount of units that are installed each five years, while for the biomass gasification route we assume a doubling of the installed units each five years. This difference is ascribed to limited availability of biomass feedstock. The amount of syngas produced in 2050 by our five routes equals the 29 EJ (approximately 1200 Mt) of total renewable syngas demand for carbon-based products in our scenario (see also Figure 3). Figure 4 shows our assumptions with regard to the deployment of each of the five renewable syngas production options (Figure 4A), as well as the cost developments (Figures 4B through 4F) for these five renewable syngas production alternatives.

The syngas production costs are broken down by their individual contributions, including CAPEX, OPEX, biomass, electricity, CO₂, H₂, and H₂O. CAPEX represents the total investment costs (incl. equipment, installation, engineering, contingency, etc.) and depends on the specific technology learning curve for each of the individual routes (see also SI). OPEX includes mainly fixed operational and maintenance costs and is a percentage of the initial investment costs. Main feedstock costs are shown separately to indicate the reliability on these components. For our base case scenario, biomass costs increase from currently (2023) 50 to 150 €/ton in 2050. We increase the costs of CO₂ from currently 50 to 150 €/ton in 2050. Electricity costs reduce from 40 €/MWh to 20 €/MWh in 2050, while green H₂ costs reduce from 5 €/kg today to 2 €/kg in 2050. Costs for H₂O remain constant at 1 €/ton and its cost contribution is negligible (and not visible in any of the graphs). The CO₂ taxation increases from 90 in 2023 to 300 €/ton in 2050.^[46] This taxation is only applied to the carbon content of the syngas and not to background emissions of the production process, and only for the fossil reference costs. This also implies that we suppose that not any fossil emissions are associated with the renewable pathways. More information on the methodology, assumptions, and data sources is provided in the SI.

The production costs of biomass gasification rise from around 280 €/ton to more than 400 €/ton in 2050 (Figure 4B). This effect is mainly caused by an increase in biomass feedstock costs, even though the energy efficiency of the process improves from 61 % in 2023 to 77 % in 2050. CAPEX and OPEX reduce slightly thanks to an LR of 13 %. Production costs are higher than those of natural gas derived syngas, but only for the low cost scenario without CO₂ taxation. At higher prices and with a CO₂ tax, the biomass gasification route seems competitive in costs over the entire time horizon (see also Figure 5 Left).

The microwave-induced plasma CO₂ conversion route produces syngas for around 2200 €/ton in 2025 (Figure 4C). The process only converts CO₂ into CO, driven by electricity, and two molar equivalents of H₂ are added separately to generate the required syngas mixture. This explains the dependency on electricity, CO₂ and H₂ as feedstocks. Costs for electricity decline mainly thanks to an improved energy efficiency of the process from 35 % in 2023 to 71 % in 2050. The contribution of CO₂ feedstock in the total production costs increases from nearly

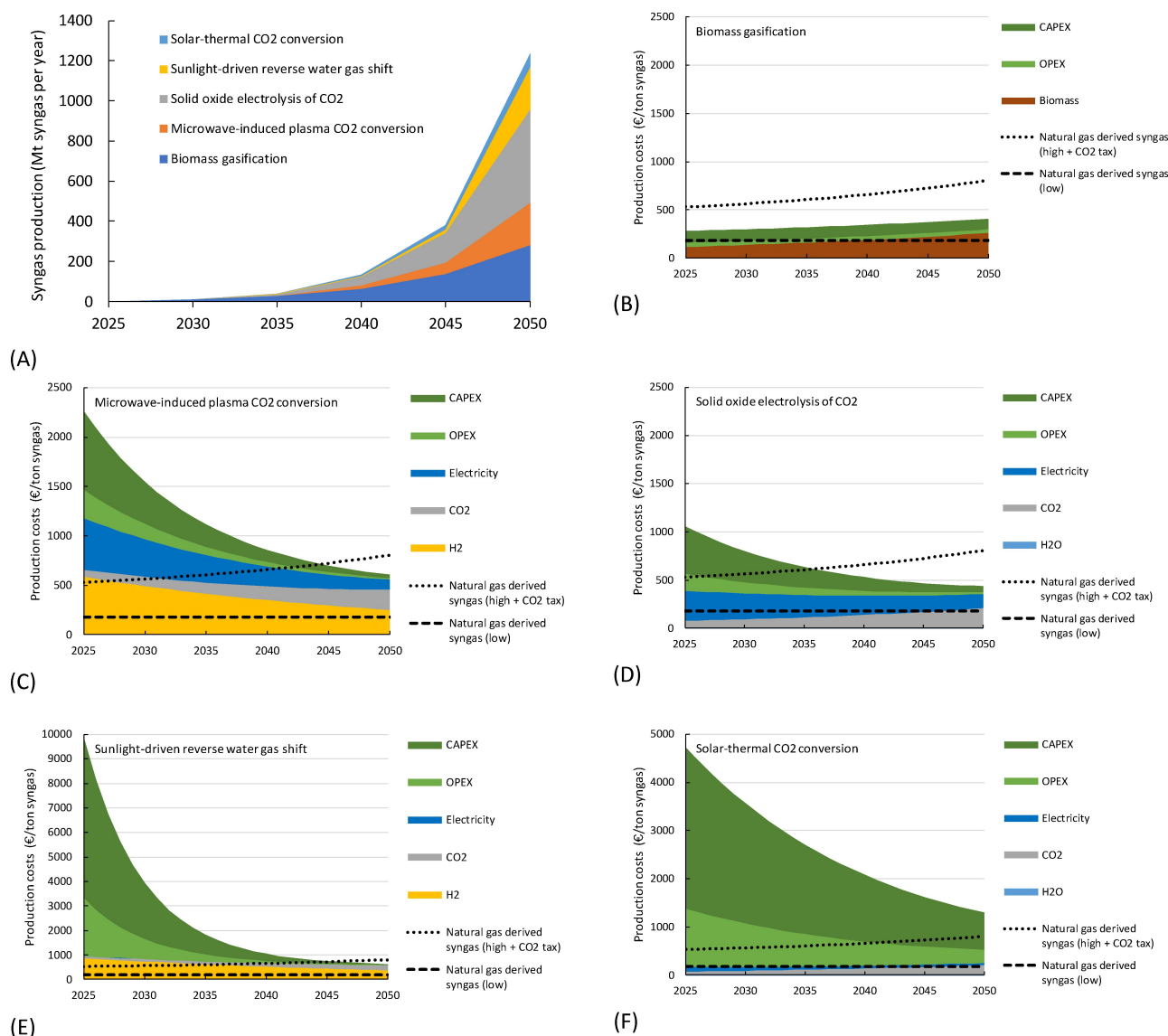


Figure 4. Deployment (A) and cost developments (B to F) for five renewable syngas production alternatives. A zoomed-in version of E is shown in Figure S1.

3% to 34% in 2050. Green H₂ costs contribute approximately 40% to the total in 2050. Thanks to substantial deployment and an LR of 15%, CAPEX reduces significantly and adds only around 6% to the total production costs of 600 €/ton syngas in 2050. Break even costs are reached with the high cost fossil reference scenario with CO₂ tax towards 2045.

Solid oxide electrolysis of CO₂ and H₂O depends, besides on CAPEX and OPEX, mainly on the costs of electricity and CO₂ (Figure 4D). Costs of CO₂ increase over time while those of electricity reduce towards 2050. Thanks to fast cost reductions in CAPEX (LR=20%), these two feedstocks, CO₂ and electricity, together represent nearly 80% of the total syngas production costs of 440 €/ton in 2050. The process additionally benefits from gains in energy efficiency from 79% in 2023 to 90% in 2050. These characteristics result in a relatively competitive process, which may reach break-even costs with the high fossil reference case with CO₂ tax towards 2036.

The current syngas production costs of sunlight-driven reverse water gas shift are very high, mainly due to high investment costs (Figure 4E). These investment costs are likely to reduce substantially when going down the technology learning curve. From today to the first 114 kt syngas production plant in 2035, CAPEX reduces by more than 90%, largely thanks to improvements in process efficiency. Another more than 90% cost reduction is realized in the next 15 years up to 2050 thanks to a combination of substantial technology deployment and a high learning rate of 24%. After around 2040, CAPEX and OPEX are not dominating the production costs anymore and H₂ and CO₂ costs become the most important components. H₂ and CO₂ account in 2050 for, respectively, 60% and 33% of the total syngas production costs of 630 €/ton. Break-even costs with the high fossil reference case with CO₂ tax are reached in 2046.

Solar thermal syngas production is also highly CAPEX intensive (Figure 4F). The feedstock costs are relatively low because only CO₂, H₂O and some electricity are required. The

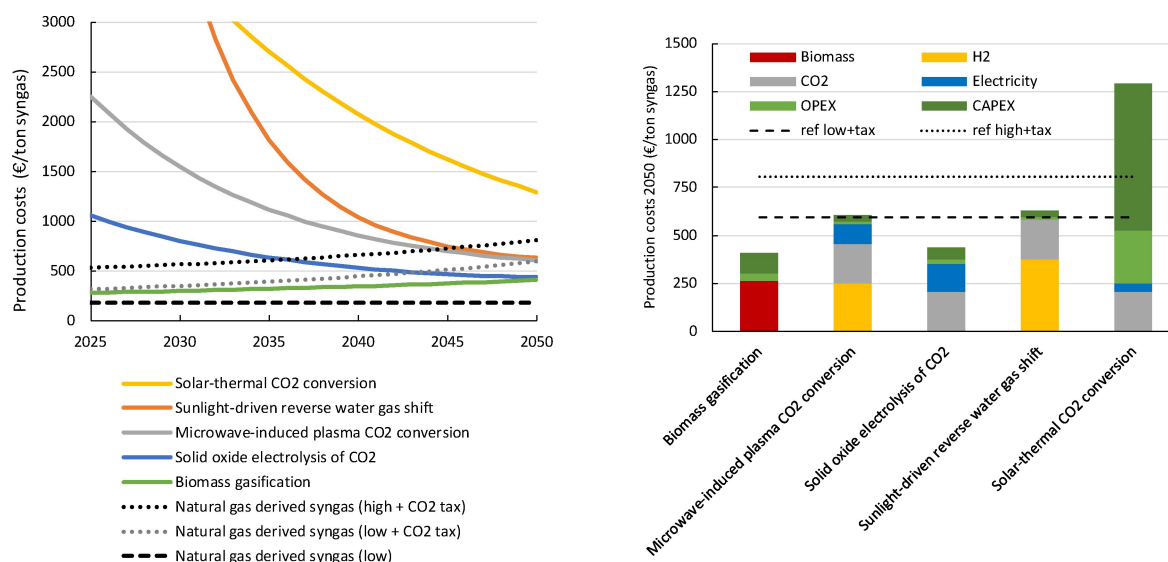


Figure 5. Comparison of cost scenarios for five renewable syngas production alternatives. Left: Cost projections of the five routes until 2050 with three natural gas derived syngas scenarios as reference. Right: Projected cost distribution of the five routes in 2050.

technology relies mainly on concentrated light to generate enough heat for catalysis. Such light concentration systems are already developed for CSP and, although we apply an LR of 18% and increase the cumulative capacity to more than 1 TW, projected investment costs only reduce by almost 80% up to 2050. Consequently, the production costs in 2050 remain for nearly 80% dominated by CAPEX and OPEX. The syngas production costs decline from around 4700 €/ton in 2025 to 1300 €/ton in 2050, the latter being more than 60% higher than the high fossil reference case with CO₂ tax.

5. Discussion

We compare the cost developments for the five renewable syngas production alternatives in Figure 5. Our modeling horizon stretches until 2050, by which year we see that cost competitiveness can be reached for four of our five routes when natural gas prices are high and a carbon tax is levied that increases from 90 €/tCO₂ today to 300 €/tCO₂ in 2050. The costs of syngas production via biomass gasification stay below the costs of the fossil reference based on a low natural gas price including CO₂ taxation. This indicates that this biomass-based route seems to have a competitive advantage over alternative renewable syngas production methods. Main challenges for this route are likely the availability of feedstock and the quality of the syngas that is produced. If biomass will become more scarce, costs are likely to go up, but to what extent is uncertain. To expand the potential of biomass gasification, the carbon efficiency can be improved by addition of renewable H₂ to the process. Making use of the plants ability to reverse water gas shift the CO₂ to CO allows almost a doubling in syngas yield, without the need of additional biomass feedstock. We should note, however, that this would have consequences for the option to store the biogenic CO₂ underground (BECCS) to

realize negative emissions. How the addition of H₂ affects the production costs and the potential for BECCS is not explored here. For synthetic fuel production, it is reported that hydrogen costs should be below 2.8 €/kg to reach break-even with the solely biomass-fed process.^[47] Routes that convert CO₂ potentially produce a relatively high quality of syngas if the feedstock CO₂ contains no other elements, such as nitrogen and sulfur. These CO₂ conversion routes do currently mainly suffer from high investment costs, but, thanks to learning, these costs likely reduce when the technologies are being deployed.

Only the solar-thermal CO₂ conversion route is not reaching break-even costs before 2050. This route depends heavily on investment costs and these are not reducing quickly due to poor learning effects. A steeper CAPEX (and related OPEX) learning curve could improve the economic feasibility of this route significantly because CO₂ costs are the only other major cost component for this route. For all CO₂ conversion routes, as here is assumed that they all operate at 100% carbon efficiency, the costs for CO₂ feedstock amount to approximately 200 €/t syngas in 2050.

The CAPEX component is less pronounced for microwave-induced plasma CO₂ conversion and solid-oxide electrolysis of CO₂ and also declines relatively fast thanks to substantial learning effects. Towards 2050, these two routes have become competitive with the high fossil reference case and the solid oxide electrolysis of CO₂ already breaks even with the low fossil references including CO₂ tax towards 2044. In 2050, electricity costs have become more relevant, especially for the electrolysis process. For the microwave-induced plasma process, the H₂ content of the syngas is directly provided by H₂ feedstock and, thus, relies on the H₂ price. This dependency on H₂ costs is also observed for the sunlight-driven reverse water gas shift process once learning has reduced the CAPEX (an indirectly OPEX) component towards 2050.

After around 20 years, the technology learning curves of our analyzed routes lowered CAPEX contributions and resulted in syngas production costs that depend mainly on the costs of energy and feedstocks, except for solar thermal CO₂ conversion. This dependency implicates that changes in biomass, electricity, CO₂, and hydrogen costs strongly affect the (relative) competitiveness of the routes. Higher biomass prices and lower electricity and CO₂ prices will reduce the costs of the CO₂ conversion routes and give these a competitive advantage (see supplementary information (SI), Figure S3). If enough biomass remains available as feedstock and the biomass price will not rise beyond 100 €/t, biomass gasification most likely will be the technology of choice for renewable syngas production (see SI, Figure S4). These results also indicate that the geographical location can have a profound effect on the relative competitiveness of the different renewable syngas production routes. At sunny locations at which both electricity and biomass are costly or limitedly available, solar-driven processes may become more attractive if CO₂ and H₂O or H₂ can be supplied. Another uncertainty in our scenarios is that if, for whatever reason, market-uptake is accelerated or a higher LR is realized for one of the routes, learning occurs faster. This would give that specific route a competitive advantage over other routes earlier in time. We should note that in our scenario, all technologies are assumed to play a role in the syngas market, while in reality it may prove to be tough for the (currently) most expensive technologies to acquire a market share. The technologies can only go through their learning curves if somehow is paid for the additional costs to “buy down” the technologies, e.g. via subsidies or niche markets. As such, it is far from clear that all these technologies will be supported to move down the learning curve.

Other elements will also play a key role during the deployment of novel technologies, such as sustainability, competition for land, regulation, financing, critical material usage, biodiversity, and social acceptance, amongst others. We recommend to investigate the influence of these elements for each of the routes and analyze more routes that may provide syngas in a competitive and renewable way. It seems likely that multiple renewable routes to produce syngas will be required, not only from a costs perspective but also to accommodate for the fast technology adoption that will be required to fulfil the potential future demand.

6. Conclusions

We analyzed how renewable syngas can replace fossil-fuel based syngas and thereby play a crucial role in the decarbonization of industry. We show that essentially all industrial applications can be subjected to decarbonization by making renewable H₂ and/or CO replace syngas produced from fossil fuel feedstocks like coal, oil and natural gas. We also quantify the present flows of these chemical building blocks, as well as those required for the transformation of industry towards a net-zero emitting sector. Furthermore, we perform a detailed techno-economic study, through which we show – at least

under standard assumptions for the learning rates that may apply to components in the corresponding industrial processes – that renewable syngas can generally become cost-competitive by 2050 with syngas traditionally generated on the basis of fossil fuels. This cost competitiveness, however, is reached for four of our five routes and only if also a couple of other conditions hold, such as natural gas prices that are at least around 3 €/GJ and carbon taxes that increase from 90 €/tCO₂ today to 300 €/tCO₂ in 2050. The relative cost competitiveness of the renewable production routes will likely depend on the steepness of the learning curves for the technologies involved as well as on the costs of feedstocks.

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Conflict of Interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data Availability Statement

The data that support the findings of this study are available in the supplementary material of this article.

Keywords: syngas · fossil fuels · renewable energy · industrial transformation · climate change

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