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Supporting Information

Towards the Use of Renewable Syngas for the Decarbonization of Industry

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Supplementary information

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Methodology

Syngas flows

To derive the different flows of syngas used for several applications, several sources has been consulted. In the tables below, a summary of the data and sources are given (see also Beerse, 2021[i]).

Table S1 Data for the flows from syngas to the applications of syngas.

Syngas to…	Efficiency	Size (Mt)	Size based on	Sources
Ammonia	98%	170	Ammonia	ii
Refining	98%	38	Hydrogen	iii
Other pure H_2	98%	4	Hydrogen	iii
Other mixed H_2	98%	30	Hydrogen	iii
Methanol	99%	100	Methanol	ii, iv, v, vi
Fischer Tropsch	99%	27	FT liquids	vii
Hydroformylation	99%	10	Oxo chemicals	viii
Iron and steel	99%	13 1000	Hydrogen + Coal	iii, ix, x
Electricity	58%	6	Coal	xi, xii, xiii
SNG	95%	6	Coal	xiv, xv, xvi
Acetic acid	73%	8	Acetic acid	xvii, xviii

Table S2 Data for the flows from fossil fuels to syngas.

… to syngas	Efficiency[ii]
Coal	76%
Natural gas	86%
Oil	81%

Assumptions for the construction of the Sankey diagram:

- The processes that do not specify the fraction of natural gas, oil or coal used in the production of the syngas use a distribution of 80% natural gas, 3% oil and 17% coal.[v] For ammonia this distribution is a slightly different with 71% natural gas, 9% oil and 21% coal. For refining and the *other* categories a distribution based on the production of hydrogen is used: 50% natural gas, 30% oil and 20% coal,[xix] because for those processes only the hydrogen in the syngas is necessary. The distribution for FT is based on the ratio CTL and GTL.[vii] The iron and steel industry is based on the quantity of CO produced in relation to the wt% of carbon in coal, according to the quantity of coal used in the iron and steel industry.[xi] It is assumed that the hydrogen that is produced in the coal gasification is used in a separate process, as it is not used in the normal process. The H_2 necessary in the iron and steel industry is produced from natural gas.[xi] Electricity, SNG and acetic acid are only produced with coal because either only CO is necessary, or because production plants only in combination with coal gasification exist.

- For the electricity production an overall efficiency of 44% is assumed.[xi,xiii]
- For FT the data from Haarlemmer *et al.*[vii] is adjusted for 85% capacity.

Table S3 Lower heating values (LHV) used in calculations for the Sankey diagram.

Chemical	LHV (PJ/Mt)[xx]
Natural gas	47.1
Oil	42[1]
Coal	29[1]
CO	10.1
H_2	119.8
Methanol	19.9
Fischer-Tropsch fuel	43[1]
SNG	50
Ammonia	18.6
Acetic acid	13.2
Syngas	23.8[1]
Oxo chemicals (butanol, isobutanol 2-ethylhexanol)	34.3[1]

Table S4 Data on syngas with a H_2/CO ratio of 2.

Chemical	Molar ratio (mol)	Weight ratio (kg)	LHV ratio (PJ/Mt)	Molecular weight (kg/kmol)
CO	1	0.875	8.8	28
H_2	2	0.125	15.0	2
Syngas		1	23.8	10.7

Costs

The syngas production costs (C_x) are calculated with equation (1) in which the total annual costs are divided by the total amount of product generated on an annual basis (P_x) (Blok & Nieuwlaar, 2016).[xxi] The discounted annualized CAPEX (with α being the capital recovery factor), the annual O&M costs (incl. equipment replacement costs), and the annual costs for feedstock *F* (for biomass, CO_2, electricity, hydrogen and water) represent the total annual costs. The capital recovery factor (α) is determined by equation (2) and is a function of the discount rate (*r*) and the lifetime of the plant (*n*). We here use a discount rate of 10% and a plant lifetime of 25 years (based on IEA (2020); Detz, *et al.* (2018))[xxii,xxiii] and vary these values in the sensitivity analysis (Figure S2). We assume that the

$$C_x = \frac{\alpha \times \mathrm{CAPEX} + \mathrm{O\&M} + \mathrm{F}}{P_x} \quad (1)$$

$$\alpha = \frac{r}{1-(1+r)^{-n}} \quad (2)$$

[1] Calculated, assumed or an average of the different kinds.

operational capacity of the plant in full load hours (FLH) is steady over the plant lifetime. The amount of FLH differs between the routes, and is further explored in the sensitivity analysis. Biomass costs increase from 50 to 150 €/ton over the explored time period of our base scenario, while we use a range of 20 to 200 in the sensitivity analysis. The costs of biomass range significantly and depend on several factors, such as the sort of biomass, the quantity, and the location, among others. The costs range from roughly 0 to 150 €/ton (dry matter) according to a recent review of which the costs for straw and logging residues amount to around 50 €/ton on average (Karras, Brosowski and Thrän 2022).[xxiv] Our biomass is assumed to be lignocellulosic with a LHV of 17.8 MJ/kg (Albrecht, et al. 2017).[xxv] The costs of CO_2 as a feedstock will depend on its source and may vary significantly between capture from different point sources or from the air (IEAGHG, 2021)[xxvi] (Keith *et al.*, 2018).[xxvii] We increase the costs of CO_2 from currently 50 to 150 €/ton in 2050, while a broader range (20-200 €/ton) is explored in the sensitivity analysis (Table S1). Electricity costs reduce from 40 €/MWh to 20 €/MWh in 2050, while we investigate a cost range of 20 to 60 €/MWh in the sensitivity analysis (IEA, 2020).[xxiii] Green H_2 costs reduce from 5 €/kg today to 2 €/kg in 2050.[xxviii] Costs for H_2O remain constant at 1 €/ton and its cost contribution is negligible (and not visible in any of the graphs) (Agora (2018)).[xxix] Costs are reported in €(2020), unless otherwise noted. Other currencies are converted to € in the year under consideration, and subsequently corrected for inflation by converting them to our reference year (2020).

Table S5. Parameters for cost analysis of renewable syngas production routes

Parameter	Selected base value 2023	Selected base value 2050	Sensitivity range	Unit
Plant lifetime	25	25	20 – 30	years
Discount rate	10	10	5 – 15	%
Euro Reference year	2020	2020		
O&M cost factor	4	4	2 – 6	% of initial
Biomass	50	150	20 – 200	€/t biomass
CO_2	50	150	20 – 200	€/t CO_2
Electricity	40	20	20 – 60	€/MWh_e
H_2	5.0	2.0	1.5 – 6.0	€/kg H_2
H_2O	1.0	1.0	0.5 – 2.0	€/t H_2O

$$C_{X_t} = C_{X_0}\left(\frac{X_t}{X_0}\right)^{-b} \quad (3)$$

$$LR = 1 - 2^{-b} \quad (4)$$

Costs are projected via the assumptions described above and in addition we apply a technology learning curve analysis for the investment costs of the five routes. A technology learning curve provides information on how costs (or another metric) reduce in relation to the cumulative installed capacity (McDonald & Schrattenholzer, 2001; Ferioli *et al.*, 2009).[xxx,xxxi] Plotting empirical data of costs versus the cumulative installed capacity on two logaritmic axes generally results in a declining straight line. The slope of this line is used to calculate the learning rate (LR), which specifies the rate (as a percentage) of cost reduction for each doubling in cumulative installed capacity. This relationship can be expressed by equation (3) in which C_{Xt} represents the costs for a cumulative installed capacity X_t, C_{X0} the initial costs at the initial cumulative installed capacity X_0, and b is the learning parameter. Parameter b relates to the LR as indicated in equation (4). The LR's and initial cumulative installed capacities of the different routes are reported in Table 2 in the main text. We have extrapolated the learning curve in two directions, starting from the reported data in the market uptake year.

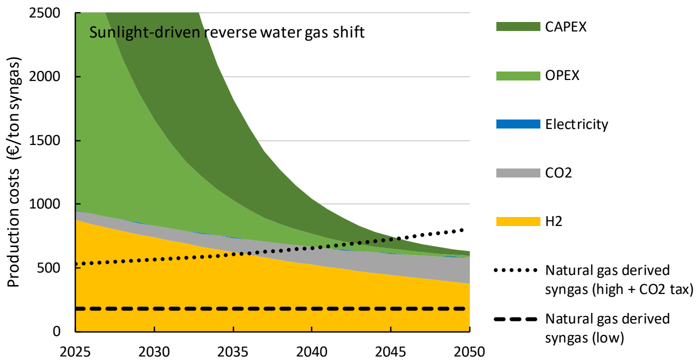
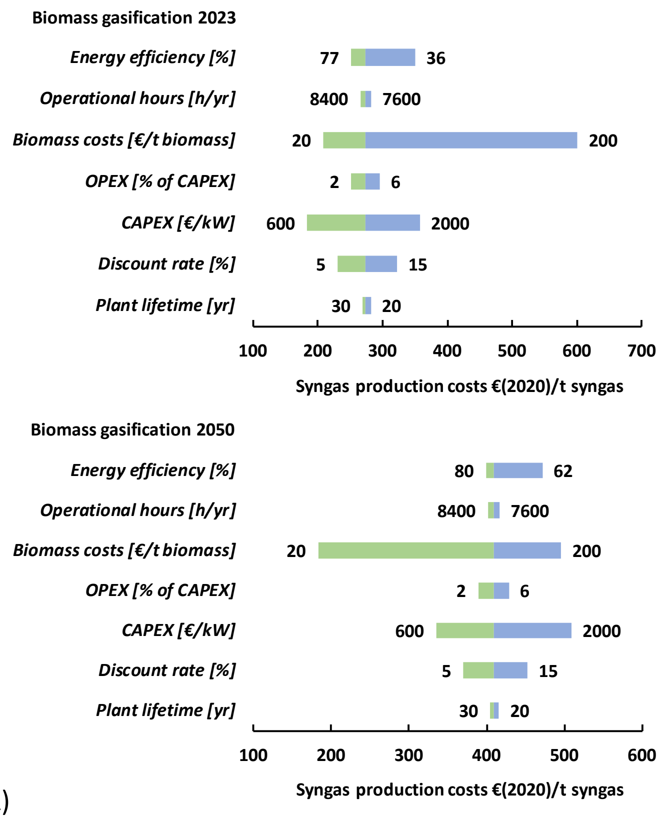
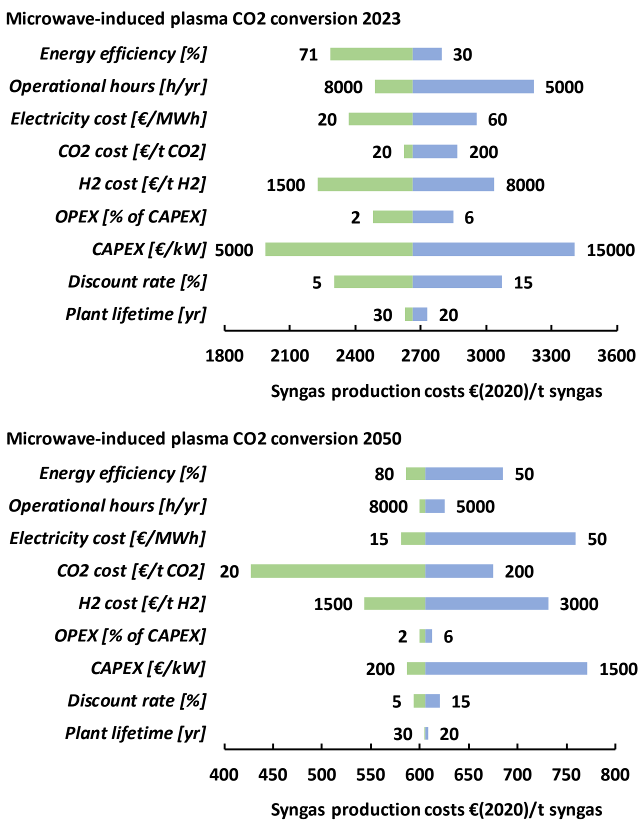


Figure S1. Zoomed-in version of Figure 4E: syngas production costs through sunlight-driven reverse water gas shift

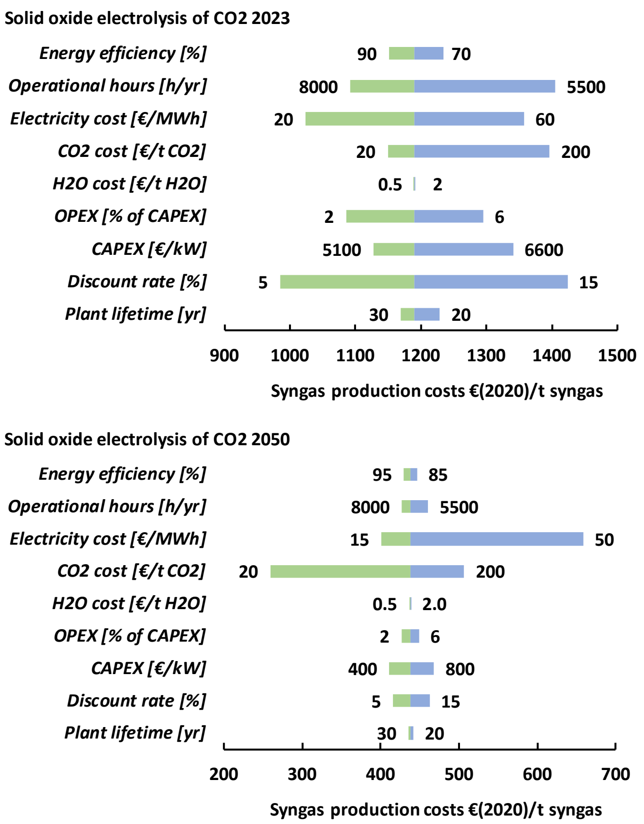
Sensitivity analysis



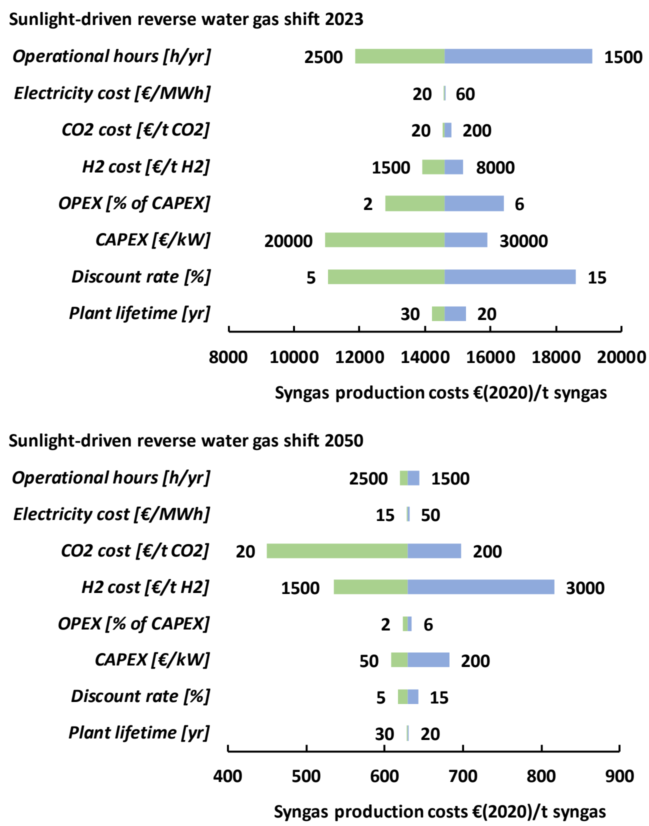
(A)


Microwave-induced plasma CO2 conversion 2023
Energy efficiency [%] 71 30
Operational hours [h/yr] 8000 5000
Electricity cost [€/MWh] 20 60
CO2 cost [€/t CO2] 20 200
H2 cost [€/t H2] 1500 8000
OPEX [% of CAPEX] 2 6
CAPEX [€/kW] 5000 15000
Discount rate [%] 5 15
Plant lifetime [yr] 30 20
1800 2100 2400 2700 3000 3300 3600
Syngas production costs €(2020)/t syngas
Microwave-induced plasma CO2 conversion 2050
Energy efficiency [%] 80 50
Operational hours [h/yr] 8000 5000
Electricity cost [€/MWh] 15 50
CO2 cost [€/t CO2] 20 200
H2 cost [€/t H2] 1500 3000
OPEX [% of CAPEX] 2 6
CAPEX [€/kW] 200 1500
Discount rate [%] 5 15
Plant lifetime [yr] 30 20
400 450 500 550 600 650 700 750 800
Syngas production costs €(2020)/t syngas

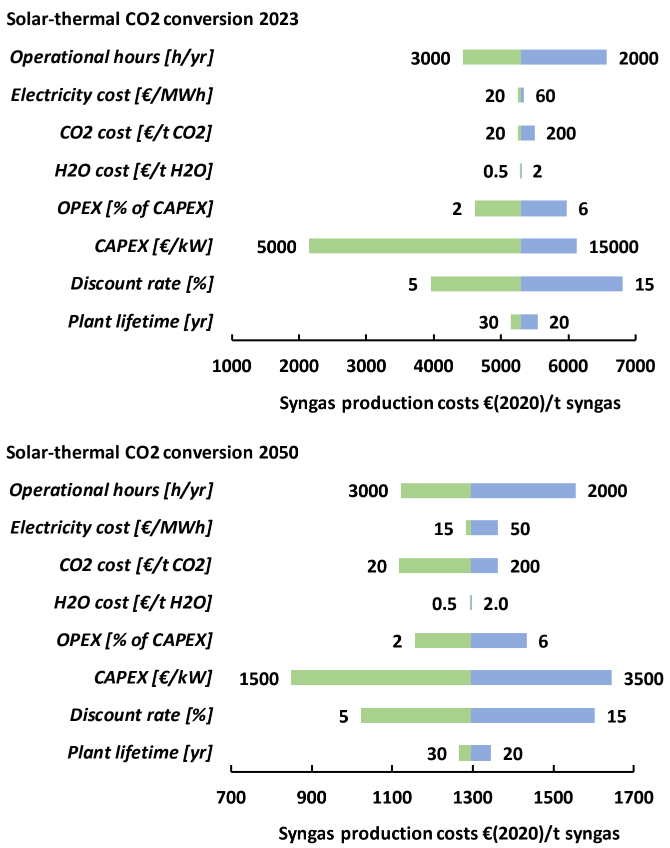
(B)


Solid oxide electrolysis of CO2 2023
Energy efficiency [%] 90 70
Operational hours [h/yr] 8000 5500
Electricity cost [€/MWh] 20 60
CO2 cost [€/t CO2] 20 200
H2O cost [€/t H2O] 0.5 2
OPEX [% of CAPEX] 2 6
CAPEX [€/kW] 5100 6600
Discount rate [%] 5 15
Plant lifetime [yr] 30 20
900 1000 1100 1200 1300 1400 1500
Syngas production costs €(2020)/t syngas
Solid oxide electrolysis of CO2 2050
Energy efficiency [%] 95 85
Operational hours [h/yr] 8000 5500
Electricity cost [€/MWh] 15 50
CO2 cost [€/t CO2] 20 200
H2O cost [€/t H2O] 0.5 2.0
OPEX [% of CAPEX] 2 6
CAPEX [€/kW] 400 800
Discount rate [%] 5 15
Plant lifetime [yr] 30 20
200 300 400 500 600 700
Syngas production costs €(2020)/t syngas

(C)



(D)



(E)

Figure S2. (A)-(E) Sensitivity analyses of five renewable syngas production routes

Varying feedstock costs

Figures S3 and S4 show sensitivity tests for the comparison of cost scenarios for five renewable syngas production alternatives, respectively optimistic for either CO_2 or biomass conversion routes. For Figure S3 increase the costs of CO_2 from currently 50 to 100 €/tCO_2 in 2050. Electricity costs reduce from currently 40 €/MWh to 15 €/MWh in 2050. Green H_2 costs reduce from 5 €/kg to 1.5 €/kg. Biomass costs increase from 50 to 200 €/ton. The CO_2 taxation increases from currently 90 to 200 €/tCO_2 in 2050, as before. For Figure S4 we increase the costs of biomass from currently 50 to 100 €/t in 2050. Electricity costs reduce from currently 40 €/MWh to 30 €/MWh in 2050. Green H_2 costs reduce from 5 €/kg to 2.5 €/kg. CO_2 costs increase from 50 to 150 €/tCO_2. The CO_2 taxation increases from currently 90 to 200 €/tCO_2 in 2050, as before.

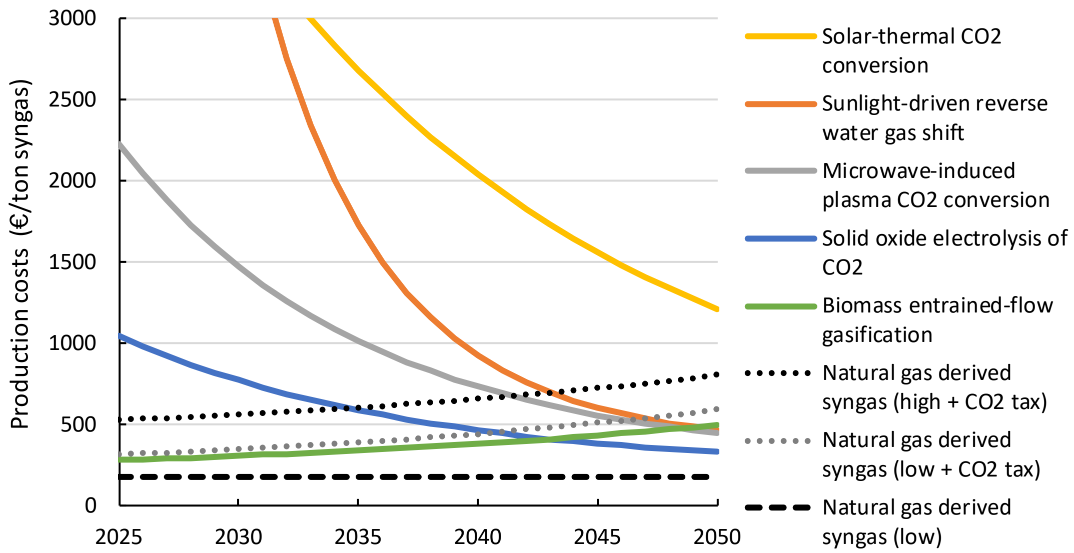


Figure S3. Comparison of costs for five renewable syngas production alternatives: sensitivity test for optimistic CO_2 conversion scenario.

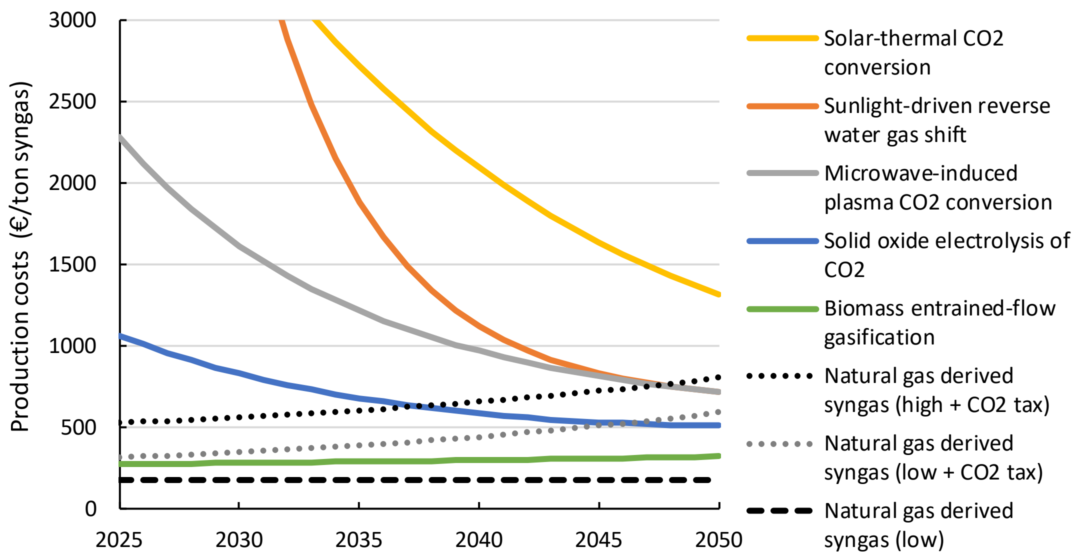


Figure S4. Comparison of costs for five renewable syngas production alternatives: sensitivity test for optimistic biomass conversion scenario.

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