Supplementary Information for

Global production potential of green methanol based on variable renewable electricity

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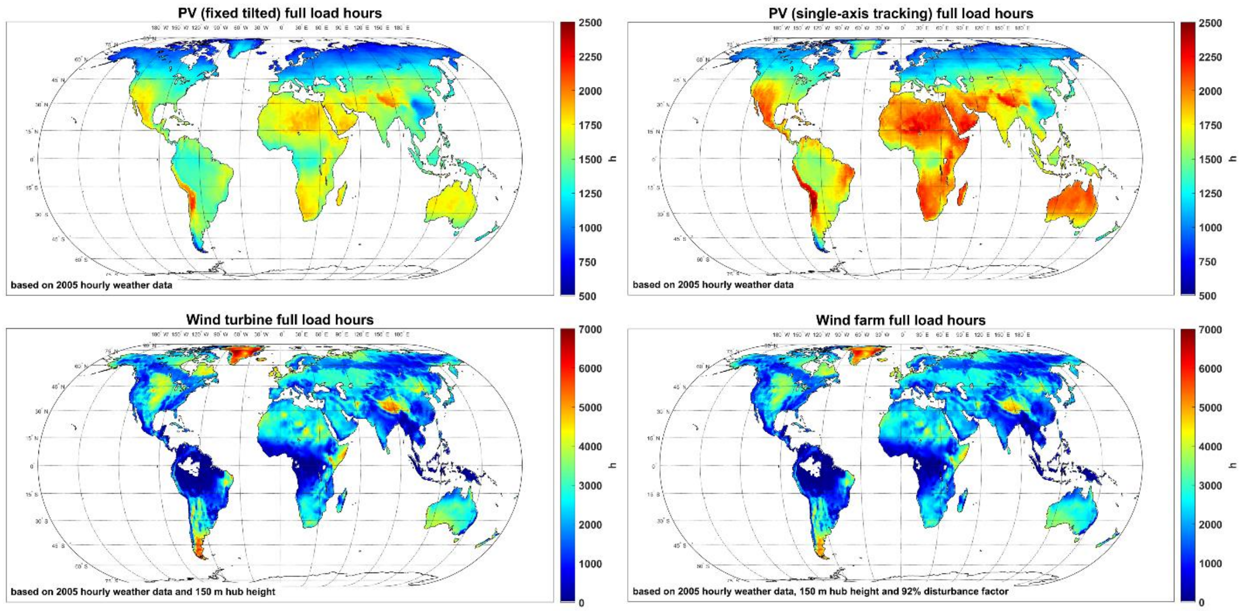

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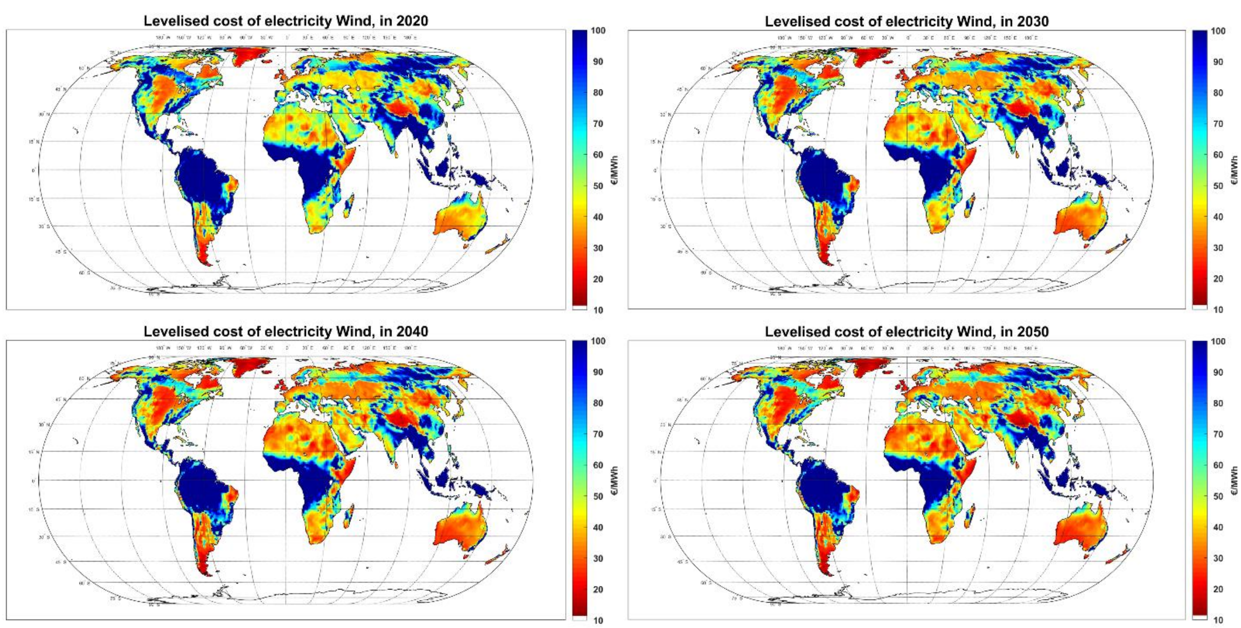

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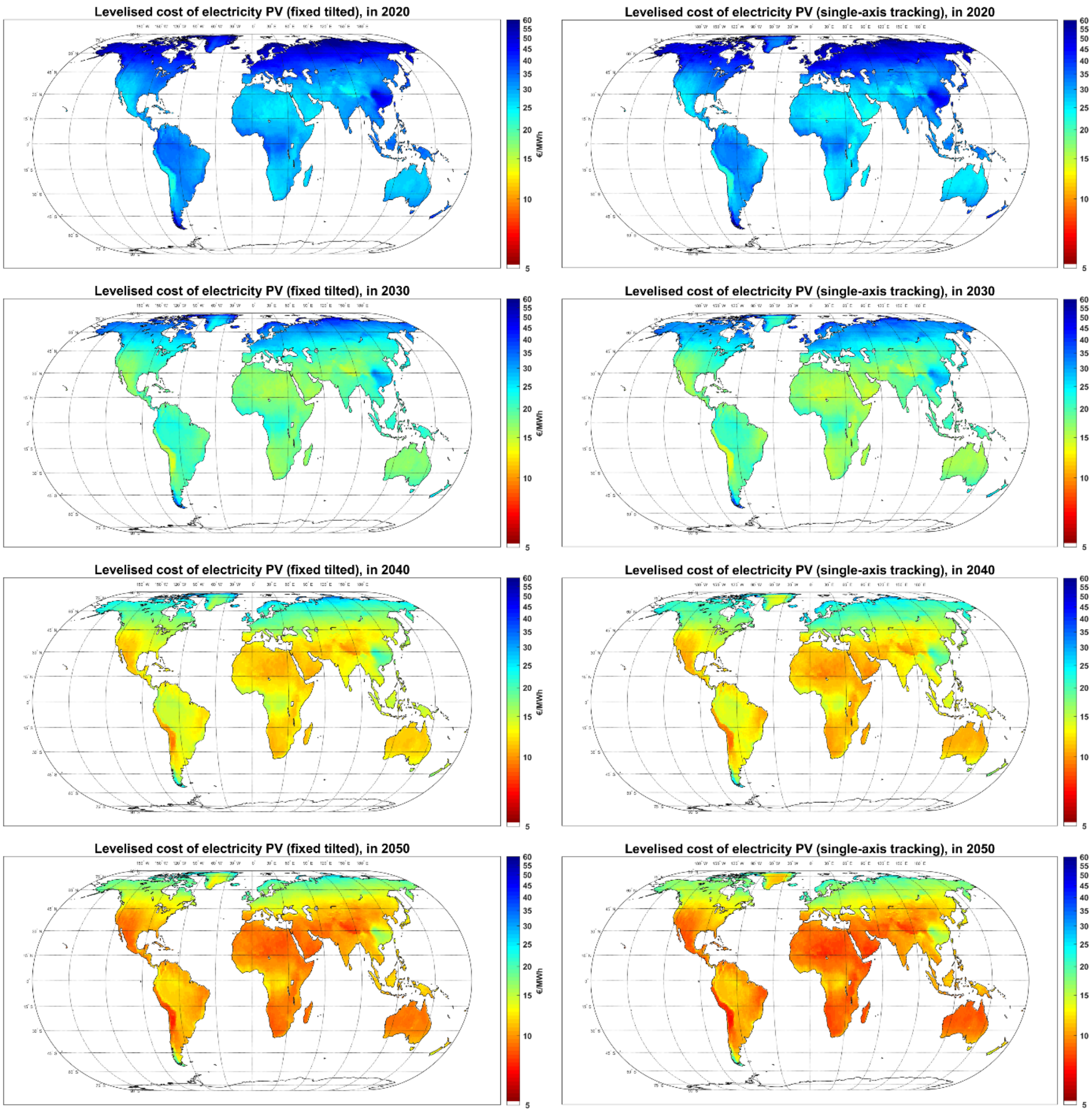

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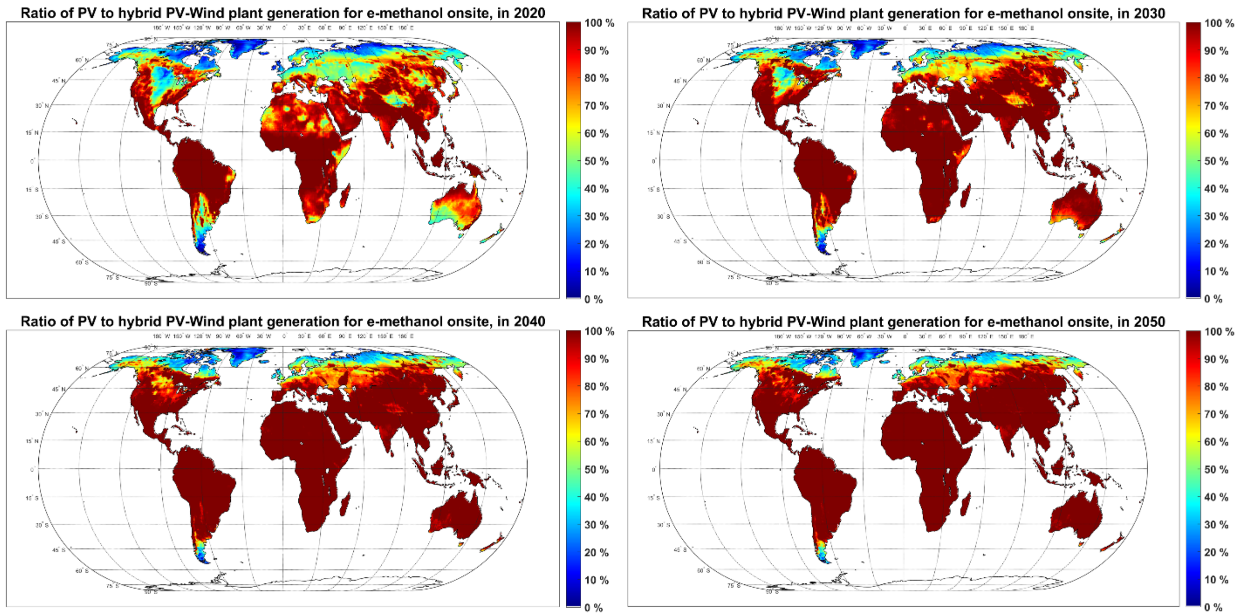

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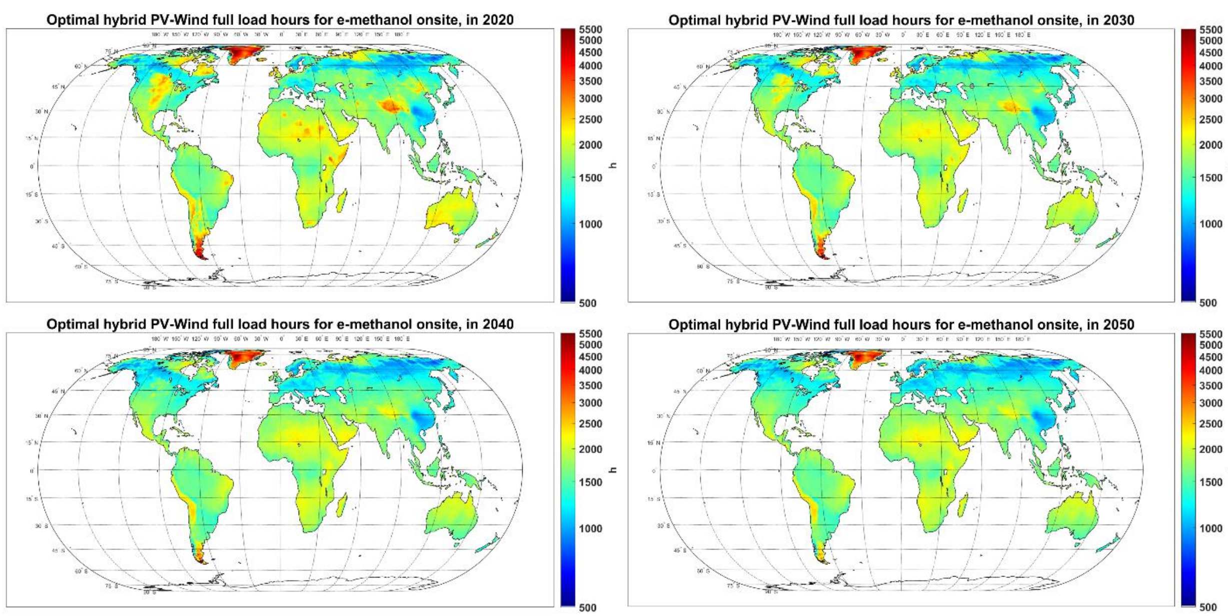

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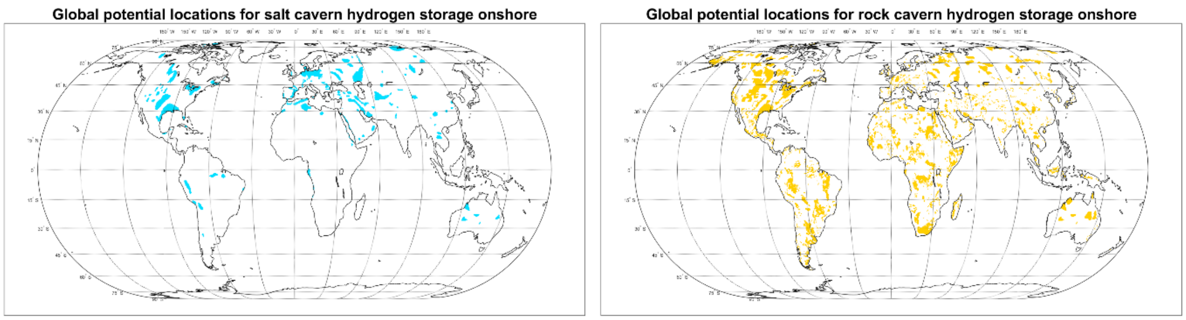

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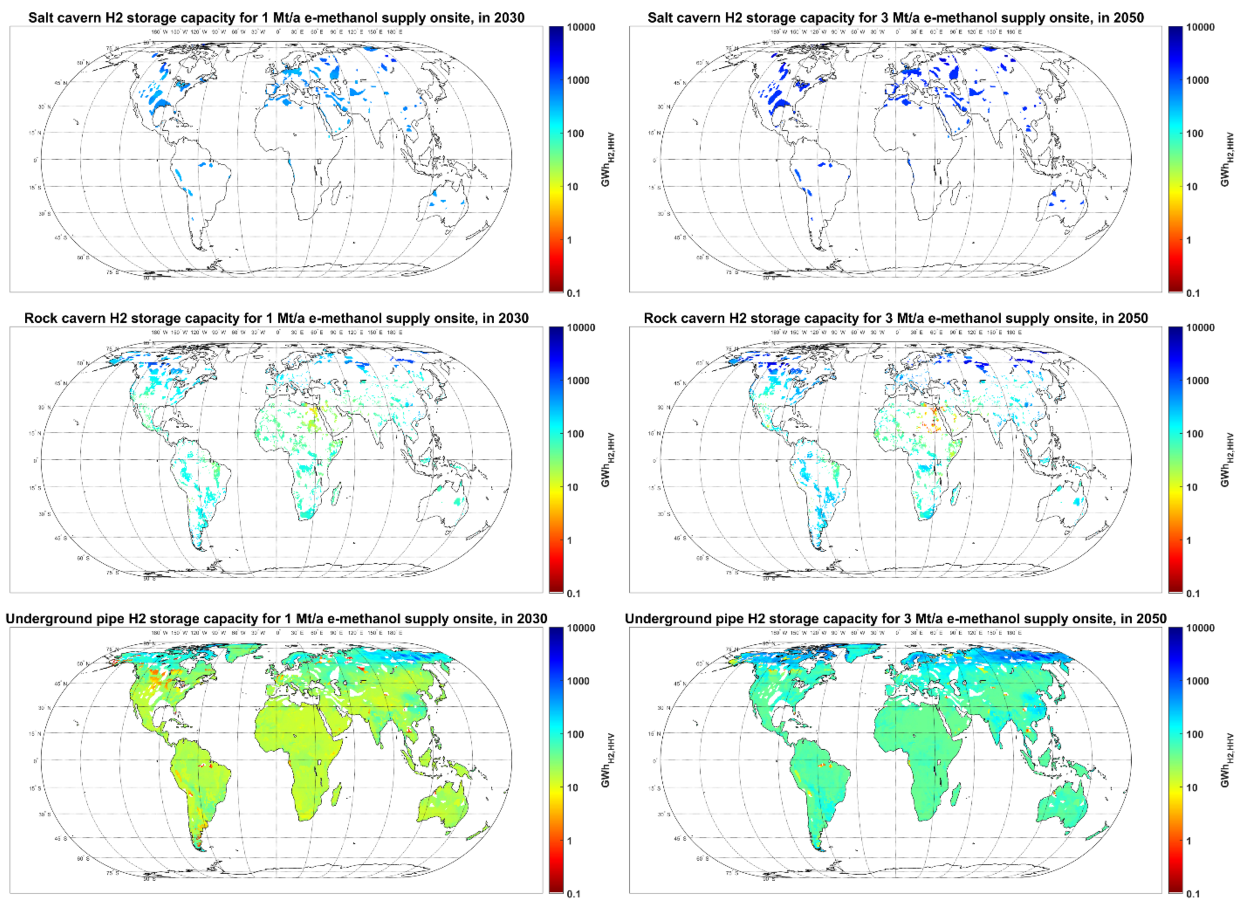

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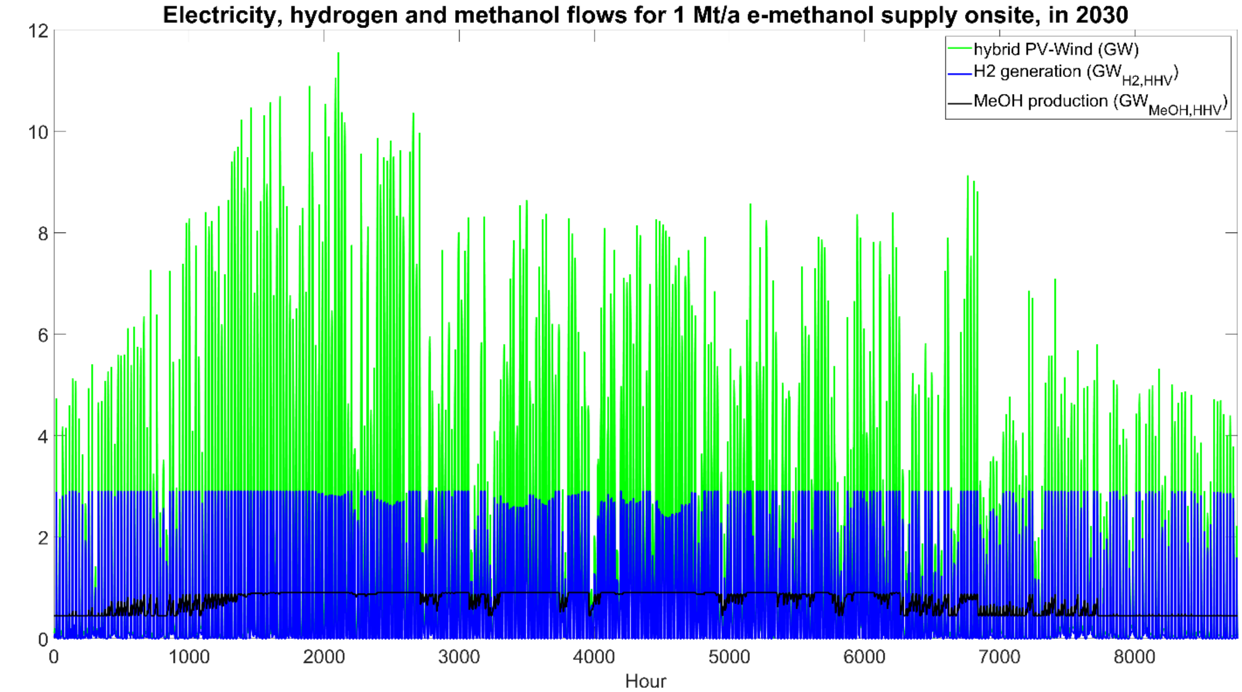

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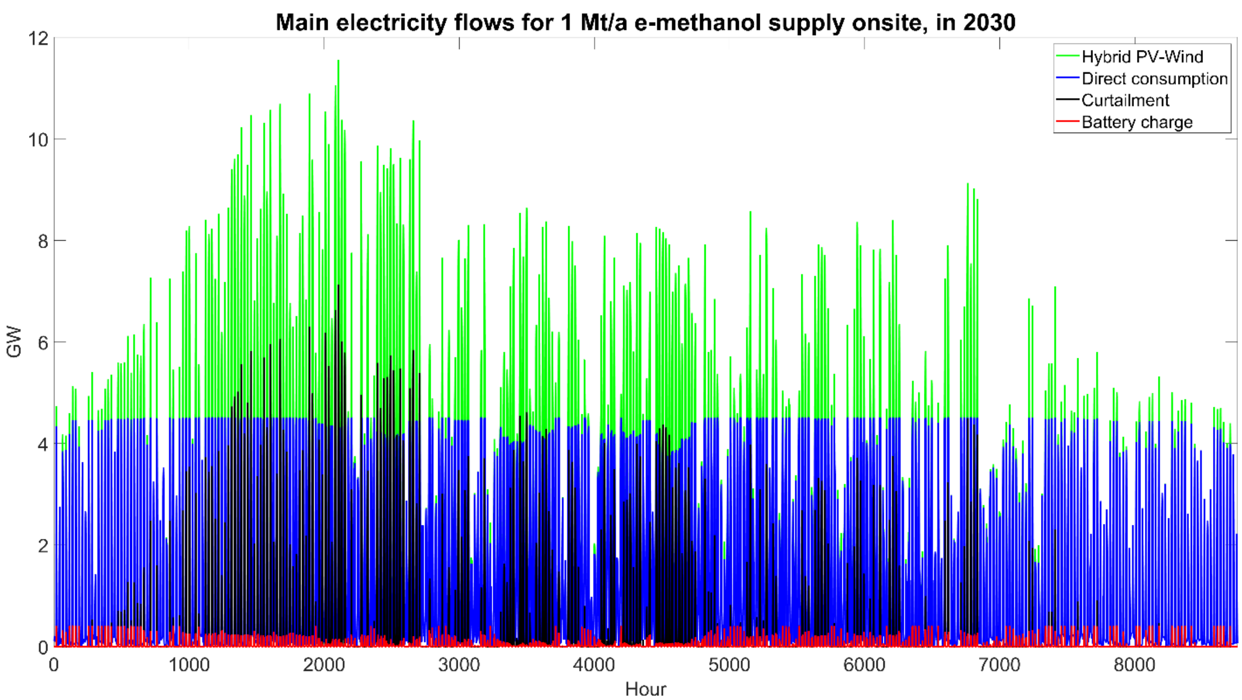

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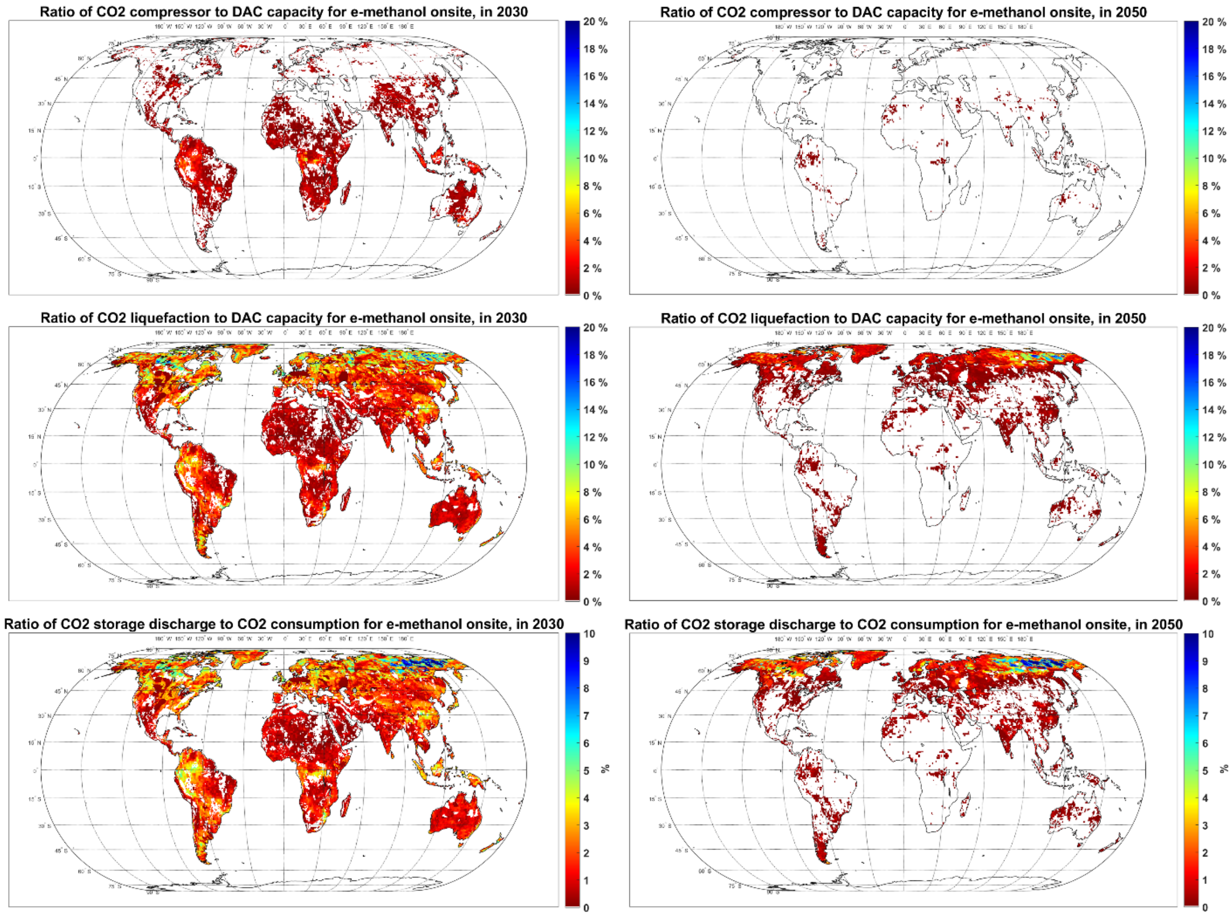

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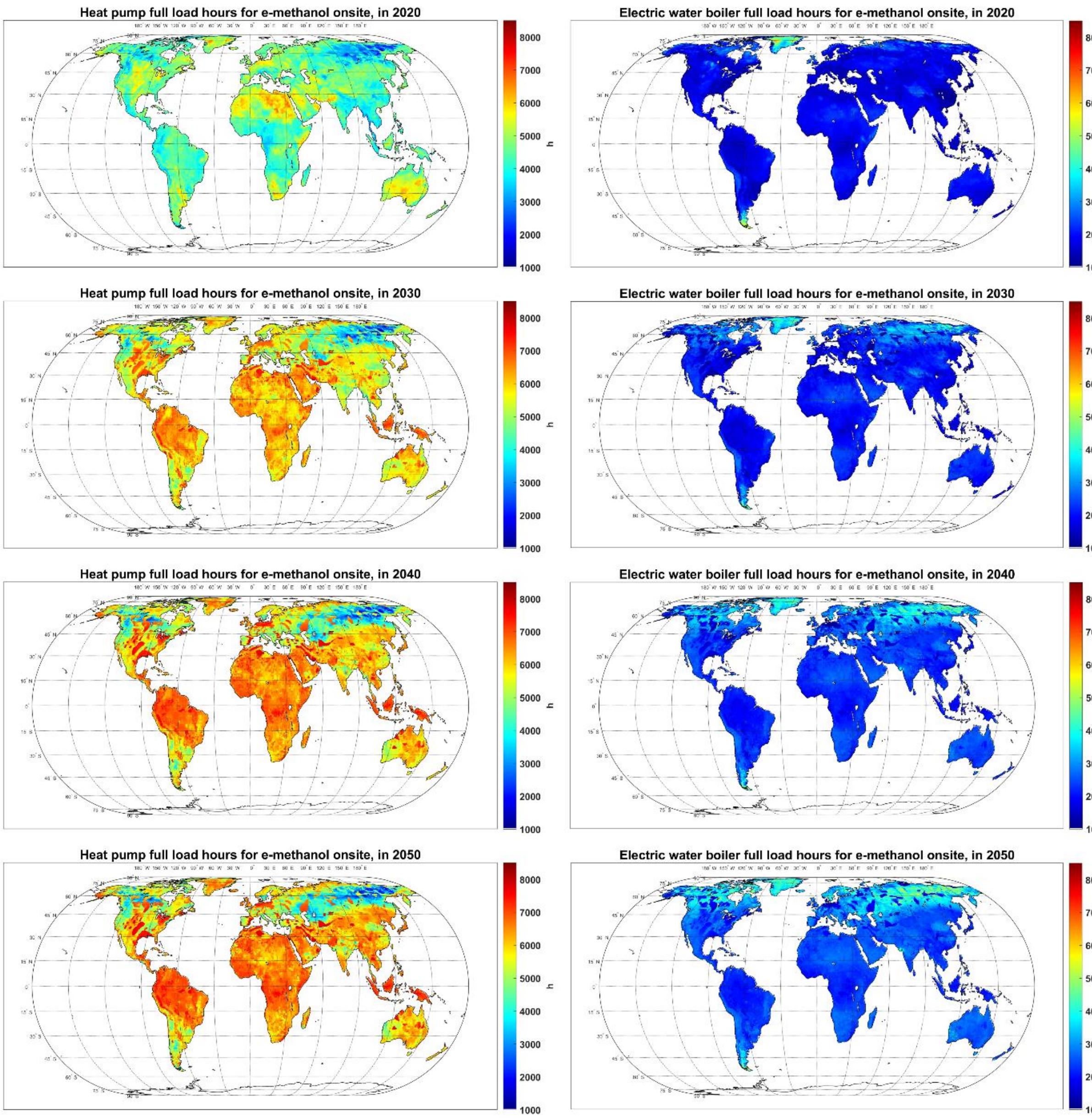

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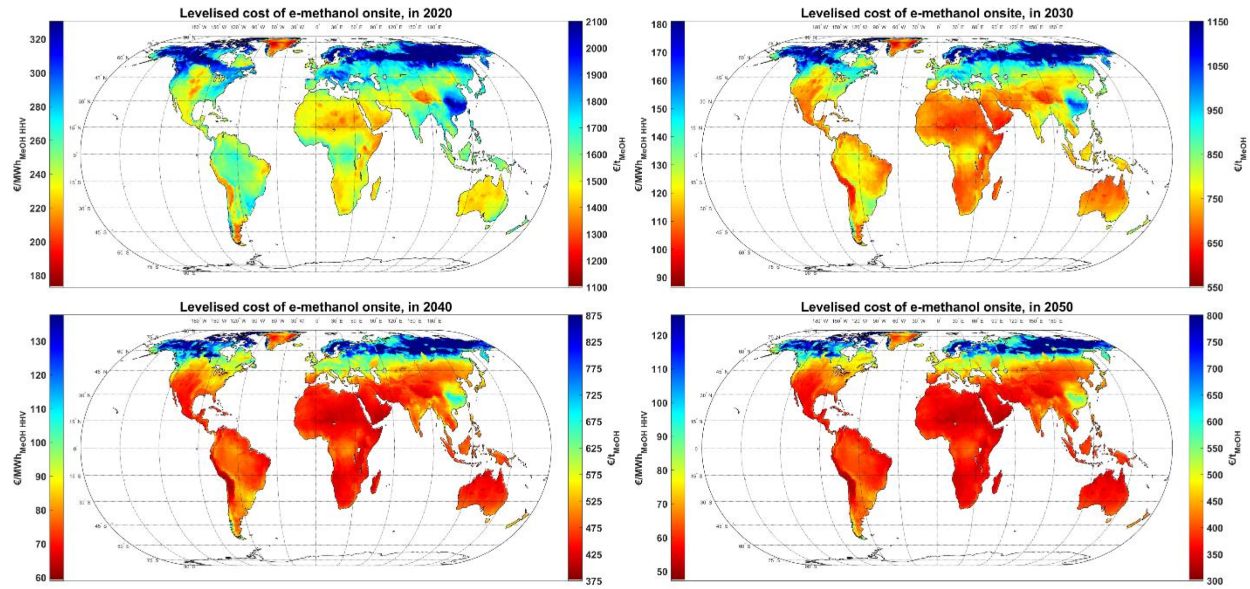

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S4. Energetic cost comparison of e-methanol and e-ammonia as fuel

While e-methanol and e-ammonia[2,3] have their own distinguished roles in chemical and agriculture industry, both are also discussed as potential sustainable fuels for long-range marine sector[4]. Thus, a cost comparison of the two e-fuels based on unified assumptions and input data is provided in this section.

The production cost of e-ammonia is based on the model by Fasihi et al.[2] with updated input data to match the assumptions for shared components with the Power-to-Methanol chain in this study. The key update is the unification of electrolyser cost.

The results presented in Figure S13 show that, at 180-220 €/$MWh_{MeOH,HHV}$, the cost of e-methanol from a 0.5 Mt_{MeOH}/a supply plant at the least cost regions in 2020 is about double the e-ammonia production cost of 90-110 €/$MWh_{NH3,HHV}$ by a 1 Mt/a ammonia supply plant. This cost difference is mainly due to relatively higher cost of atmospheric CO_2 capture for methanol synthesis compared to the cost of atmospheric N_2 capture for ammonia synthesis.

By 2030, as the cost and energy efficiency of DAC plants improve, together with the deployment of 1 Mt/a methanol supply plants at lower capex, the cost of e-methanol at best sites declines by about 50% to 94-104 €/$MWh_{MeOH,HHV}$. Comparatively, the cost of e-ammonia would decline by about 30% to 65-75 €/$kWh_{NH3,HHV}$. By 2050, the gap between production cost of e-methanol and e-ammonia further declines to about 10 €/$MWh_{th,HHV}$ (or ~25%) for 50-55 €/$MWh_{MeOH,HHV}$ and 39-45 €/$MWh_{NH3,HHV}$.

While the cost of e-methanol production remains higher than e-ammonia, choosing one as potential future sustainable marine fuel is affected by other factors. For example, due to the toxicity and gaseous phase of ammonia at ambient temperatures, methanol is a better option with respect to the cost and safety of fuel handling and transportation. On the other hand, e-ammonia provides the potential to fully eliminate carbon from the fuel supply system, though handling its higher NO_x emissions could be a challenge[5]. In addition, all technologies for e-ammonia production are mature and available at industrial scale today, whereas the realisation and scale of e-methanol production is largely dependent on future development of DAC technologies, as sustainable and unavoidable point sources are limited and may not match well with the sites of low-cost hydrogen availability[6].

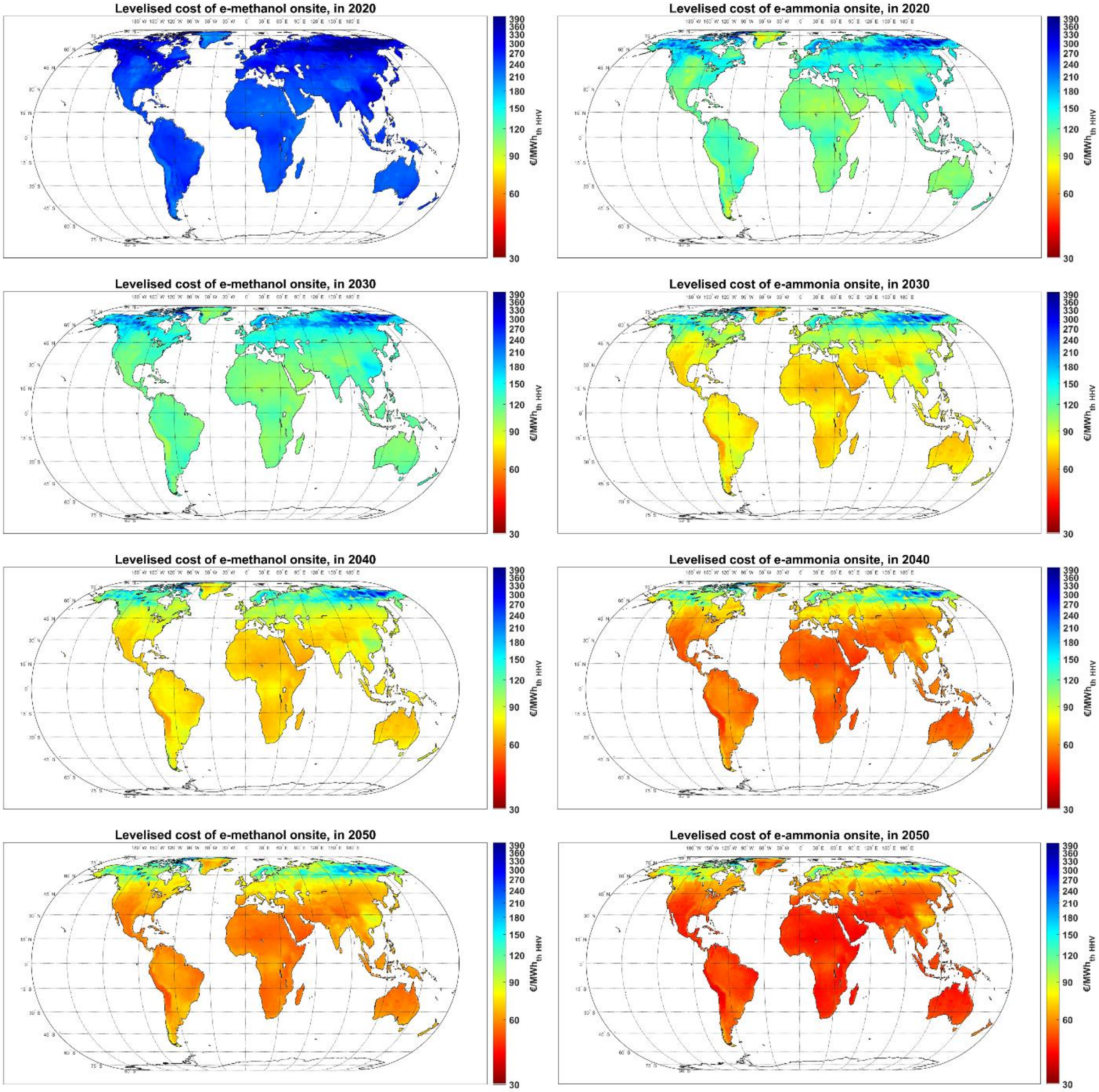


Fig. S13. Levelised cost of e-methanol (left) and e-ammonia (right) *Onsite* in 2020-2050.

S5. Cost benefits of integrated Power-to-Methanol-Ammonia plants

e-Methanol and e-ammonia could potentially have a complementary relation at the production stage. The high temperature waste heat from ammonia synthesis could be used as a source of heat for DAC units in the Power-to-Methanol chain. Thus, a combined Power-to-Ammonia-Methanol system (Fig. S14) has been modelled to assess the additional benefits of heat integration in 2030 and 2050 at different annual ammonia to methanol supply ratios.

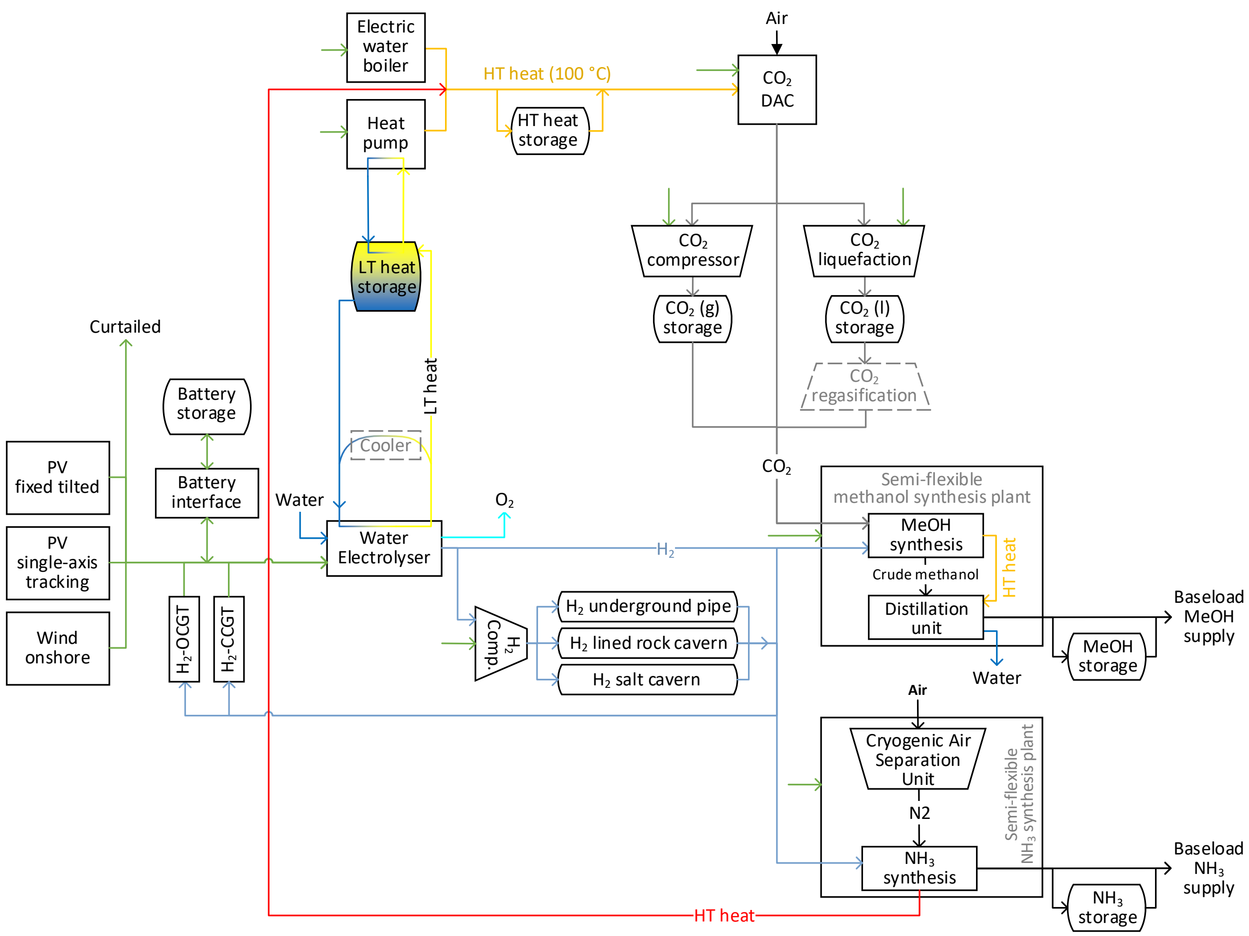


Fig. S14. Integrated Power-to-Methanol-Ammonia *Onsite* model configuration. Hydrogen-fuelled gas turbines are considered from 2030 onwards. Abbreviations: H_2- fuelled open cycle gas turbine (H_2-*OCGT)*, H_2-fueled combined cycle gas turbine (H_2-*CCGT)*, compressor (Comp.), high temperature heat (HT heat), low temperature heat (LT heat), CO_2 direct air capture (DAC).

In the integrated Power-to-Methanol-Ammonia system, methanol and ammonia synthesis units share the same power and hydrogen supply systems. The shared power and hydrogen systems have higher capacities to meet the elevated demands but could potentially benefit from system coupling for a relatively smaller overall capacity. The additional low-temperature waste heat from the elevated hydrogen production system is available as a heat source for the heat pump and the excess high temperature heat from the ammonia synthesis plant is added to the portfolio of high temperature heat resources. e-Ammonia production in Fasihi et al.[2], adopted from Morgan[7], is based on the Haber-Bosch process at 150 bar and 480 °C, which generates 1188 kWh of heat (at 108−394 °C) per tonne of ammonia. However, this design did not consider steam generation and 31% of generated heat (362 kWh/t_{NH3}) is at 108 °C which may not be suitable for heat delivery at 100 °C for utilisation by DAC units. On the other hand, Frattini et al.[8] reported on 1129 kWh of high temperature excess heat per tonne of e-ammonia production from a Haber-Bosch ammonia plant at 250 bar and 550 °C (888 kWh at 550 °C from the synthesis reactor, and 241 kWh at 150 °C from the compressors' cooling system). While such reactor conditions differ to some extent from those in Fasihi et al.[2], the are no major differences and the overall heat generations are comparable. Thus, Frattini et al.[8] is chosen for representing the full potential of e-ammonia plants for delivering excess heat at temperatures above 100 °C. On the other hand, as the energetic efficiency of DAC increases over time, the e-methanol production system would have a heat demand of 4380, 1936, 1565 and 1432 kWh_{th}/t_{MeOH} in 2020, 2030, 2040 and 2050, respectively. Therefore, these process conditions suggests that, to supply the total heat demand of e-methanol plants by the waste heat from a standard 1 Mt/a e-ammonia supply plant, the annual e-methanol supply should be limited to 0.26, 0.58, 0.72 and 0.79 Mt in 2020, 2030, 2040 and 2050, respectively. However, e-ammonia plants are expected to be significantly larger to benefit from economies of scale. To study such counter effects, the annual e-ammonia supply from the integrated ammonia plant is set at 1 Mt/a in all scenarios, while the e-methanol supply is set at 0.5 and 1 Mt/a in 2030, as well as 1 and 3 Mt/a in 2050.

Equation S1 is used to evaluate the cost of e-methanol production in the integrated methanol-ammonia system. All the potential benefits of system integration and utilisation of waste heat from ammonia synthesis are assumed to be allocated to the cost reduction of e-methanol supply.

$$LCOF_{MeOH,integrated}[€/t_{MeOH}] = \frac{\text{Annualised Cost}_{integrated\ system}[\text{M€}] - LCOF_{NH3,solo}\left[\frac{€}{t_{NH3}}\right] \cdot 1\ Mt_{NH3}}{e\text{-}methanol\ supply\ from\ MeOH\text{-}NH3\ integrated\ system\ [Mt]} \quad \text{(S1)}$$

As illustrated in Figure S12, the heat integration by co-production of 1 Mt/a of e-methanol and 1 Mt/a of e-ammonia in 2030 could reduce the cost of e-methanol by 20−30 €/t_{MeOH} (3−5 €/$MWh_{MeOH,HHV}$) in most parts of the world, with cost reductions up to 50 €/t_{MeOH} (8 €/$MWh_{MeOH,HHV}$) at latitudes above 55 °N. Such absolute cost reductions are equivalent to 3−5% cost drop compared to the Base Cost Scenario (BCS).

The benefits of heat integration in most regions could be increased to 30−50 €/t_{MeOH} (5−8 €/$MWh_{MeOH,HHV}$) by reducing the size of e-methanol supply to 0.5 Mt/a in the hybrid system, while the cost reduction at latitude above 55 °N could be 70−100 €/t_{MeOH} (11−16 €/$MWh_{MeOH,HHV}$), representing a 5−7% cost decline.

In 2050, combining the reference plant for 3 Mt/a e-methanol supply with 1 Mt/a ammonia supply plant would only reduce the cost of e-methanol supply by 5−10 €/t_{MeOH} (0.8−1.6 €/$MWh_{MeOH,HHV}$ or ~2%), with parts of the Northern regions reaching 10−15 €/t_{MeOH} (1.6−2.4 €/$MWh_{MeOH,HHV}$ or 2−3%) cost reduction. The lower cost reduction in 2050 compared to 2030 is associated with 55% lower heat integration per tonne of e-methanol as a result of 27% lower heat demand by DAC units and increasing the size of the integrated methanol plant from 1 to 3 Mt/a supply. In addition, heat could be generated for lower costs by cheaper electricity and heat pumps in 2050 compared to 2030, which makes the availability of partial free waste heat less relevant in 2050.

The results show that, unlike 2030, down-scaling the integrated e-methanol plant from 3 to 1 Mt/a supply in 2050 to elevate the share of waste heat supply per tonne of e-methanol would increase the cost of e-methanol production from the integrated system in most parts of the world, as the gain by higher share of waste heat supply is less than the loss of economies of scale for the methanol synthesis unit. Nevertheless, e-methanol from the 1 Mt/a integrated methanol supply system would still be 1−6 €/t_{MeOH} (0.16−0.94 €/$MWh_{MeOH,HHV}$ or 0.5−1.5%) lower in cost compared to the Base Cost Scenario with a solo 3 Mt/a methanol supply system. Thus, scaling the methanol plant has a larger impact on e-methanol production cost than heat integration from ammonia plant in most parts of the world in 2050. An exception would be some Northern regions beyond 60 °N, where the cost reduction of e-methanol is higher for the integrated system with lower methanol plant as more costly power and hydrogen balancing would be avoided.

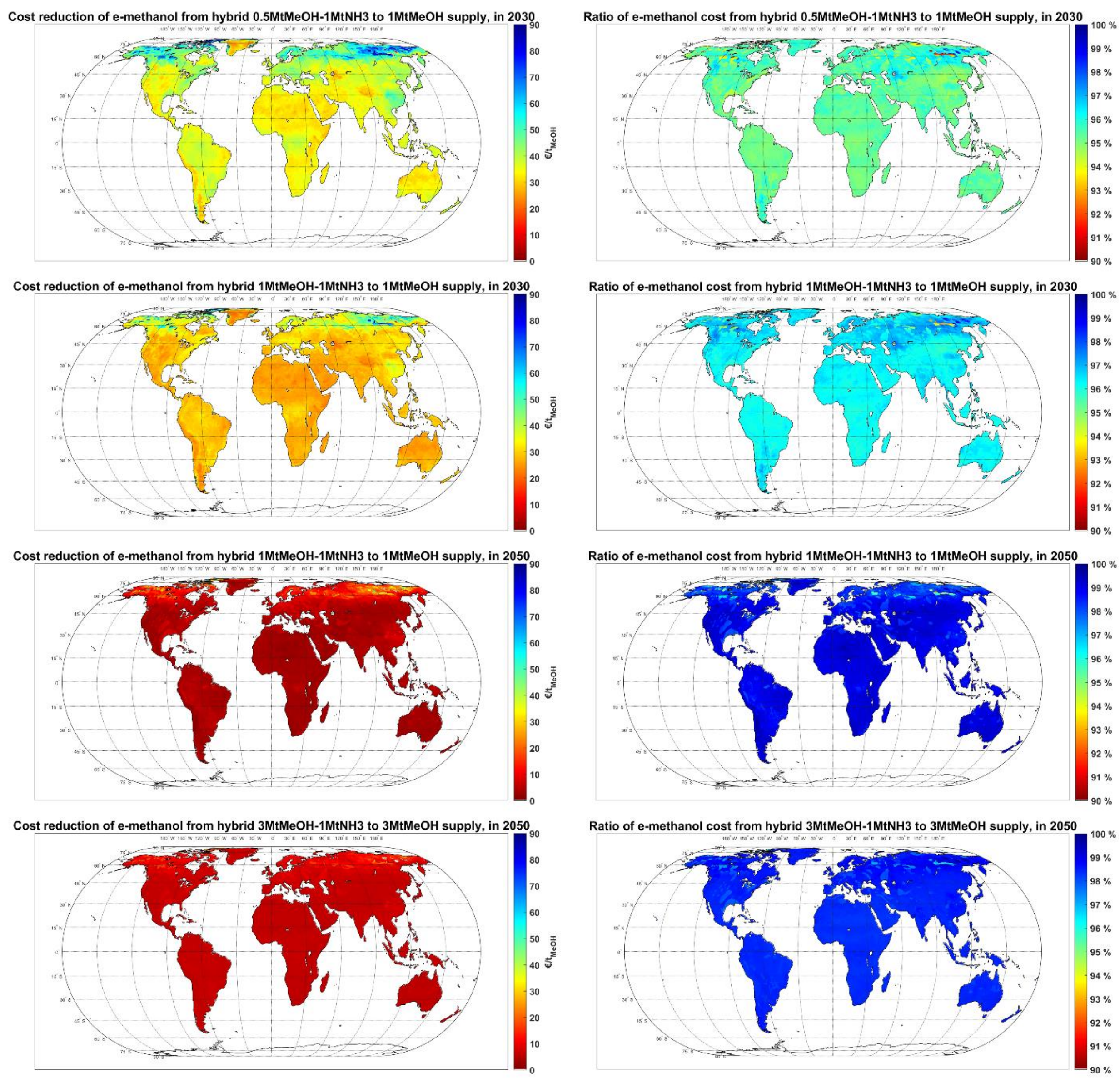


Fig. S15. Cost reduction of e-methanol in integrated Power-to-Methanol-Ammonia synthesis plants compared to solo e-methanol plants *Onsite* in absolute (left) and relative (right) values in 20230 (top and centre top)2050 (centre bottom and bottom).

S6. Sensitivity Analyses

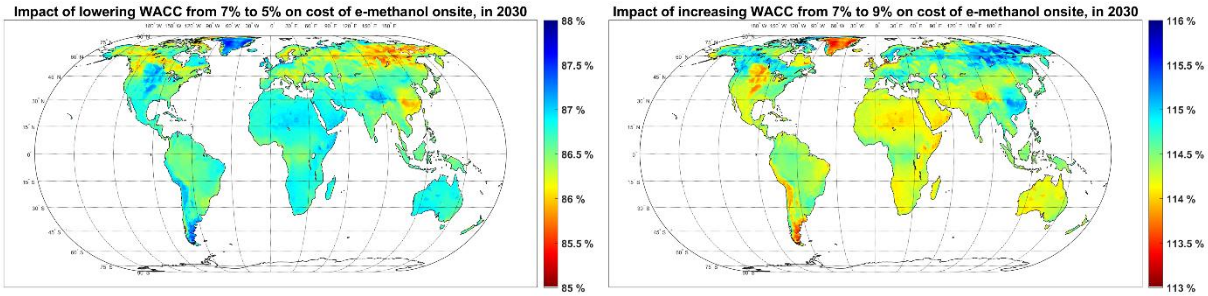


Fig. S16. Impact of decreasing WACC to 5% (left) and increasing WACC to 9% (right) in comparison to e-methanol production cost by a WACC of 7% in 2030.

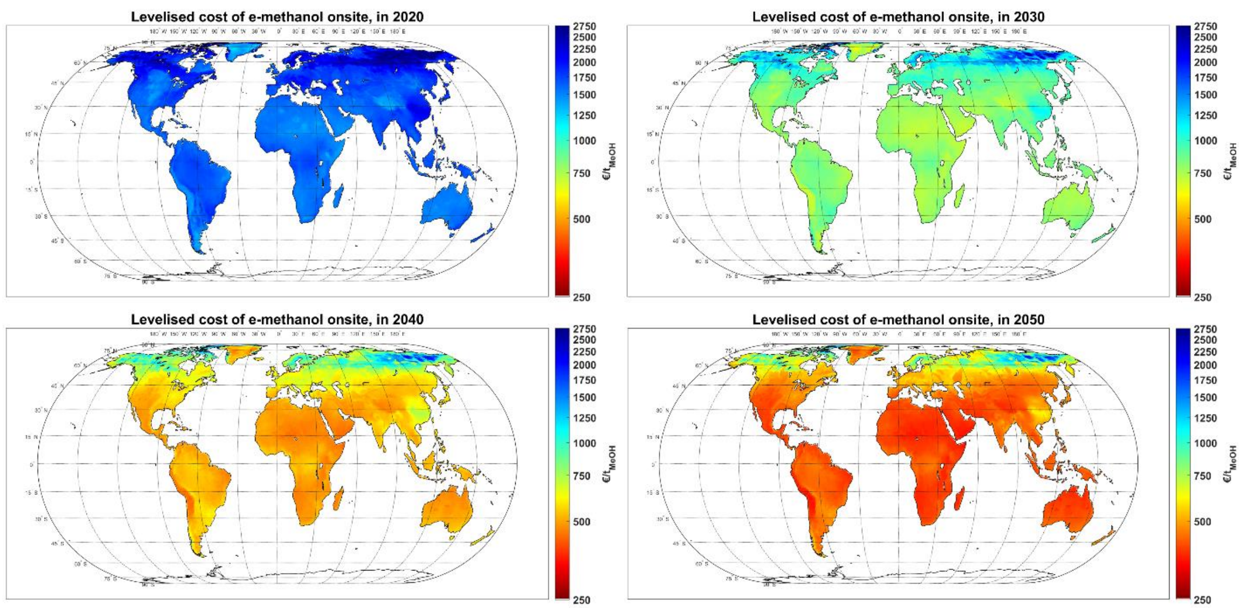


Fig. S17. Levelised cost of e-methanol *Onsite* in 2020 (top, left), 2030 (top, right), 2040 (bottom, left) and 2050 (bottom, right) for the *High-Cost Scenario*.

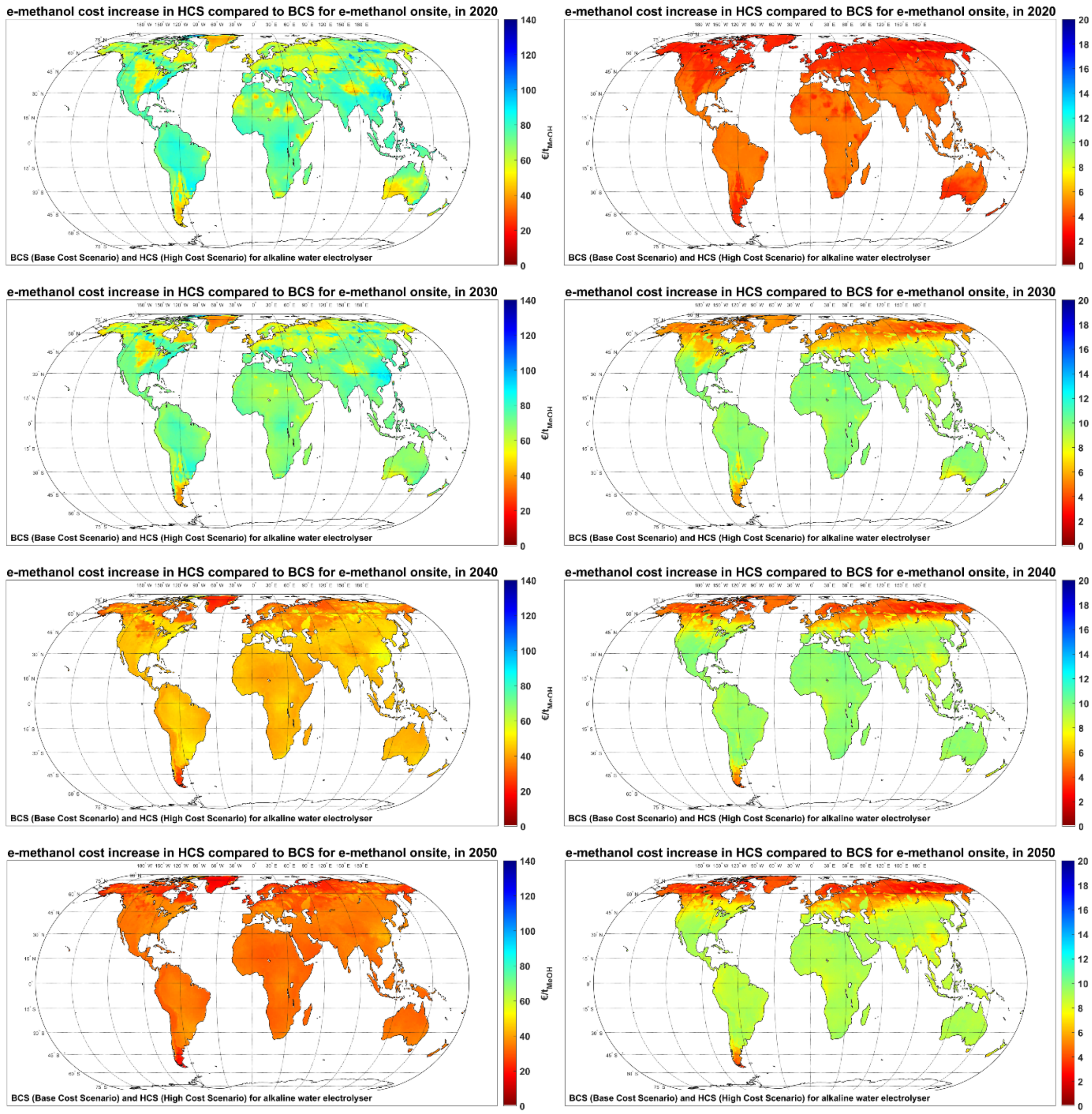
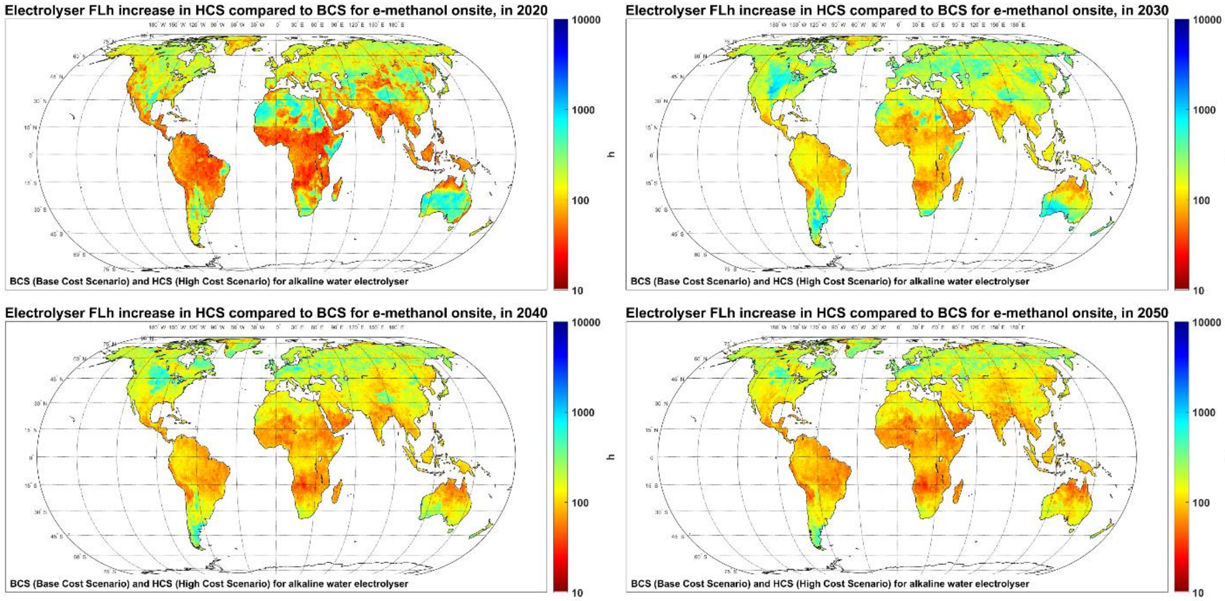


Fig. S18. Impact of the High-Cost Scenario for electrolyser capex and fixed opex on the levelised cost of e-methanol *Onsite* in 2020-2050.



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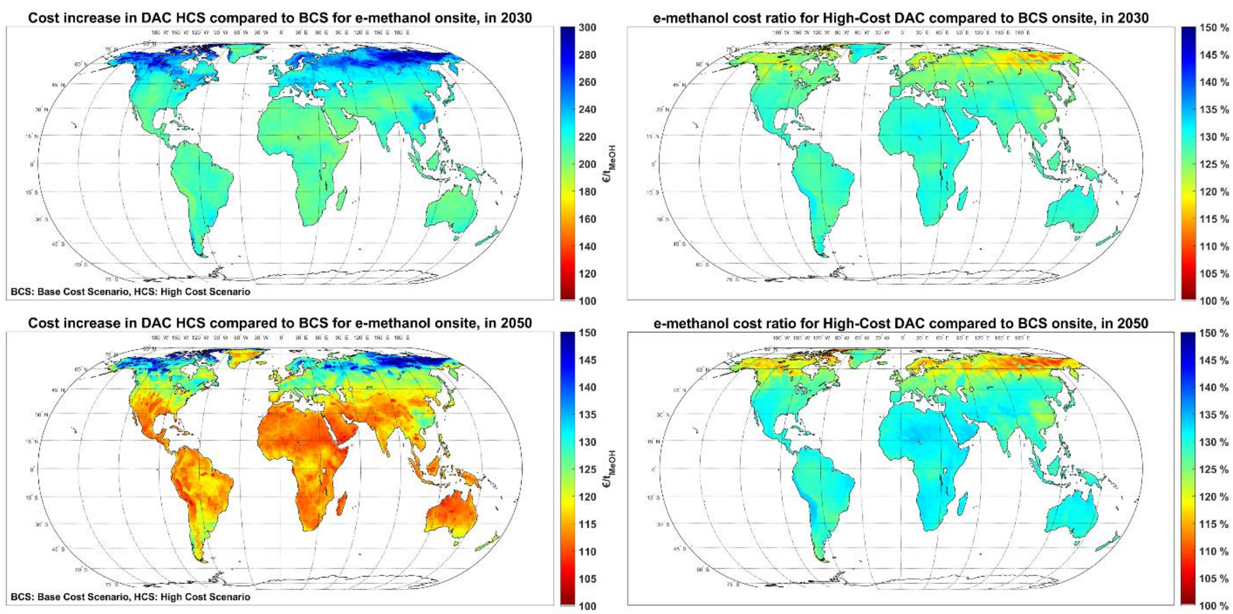

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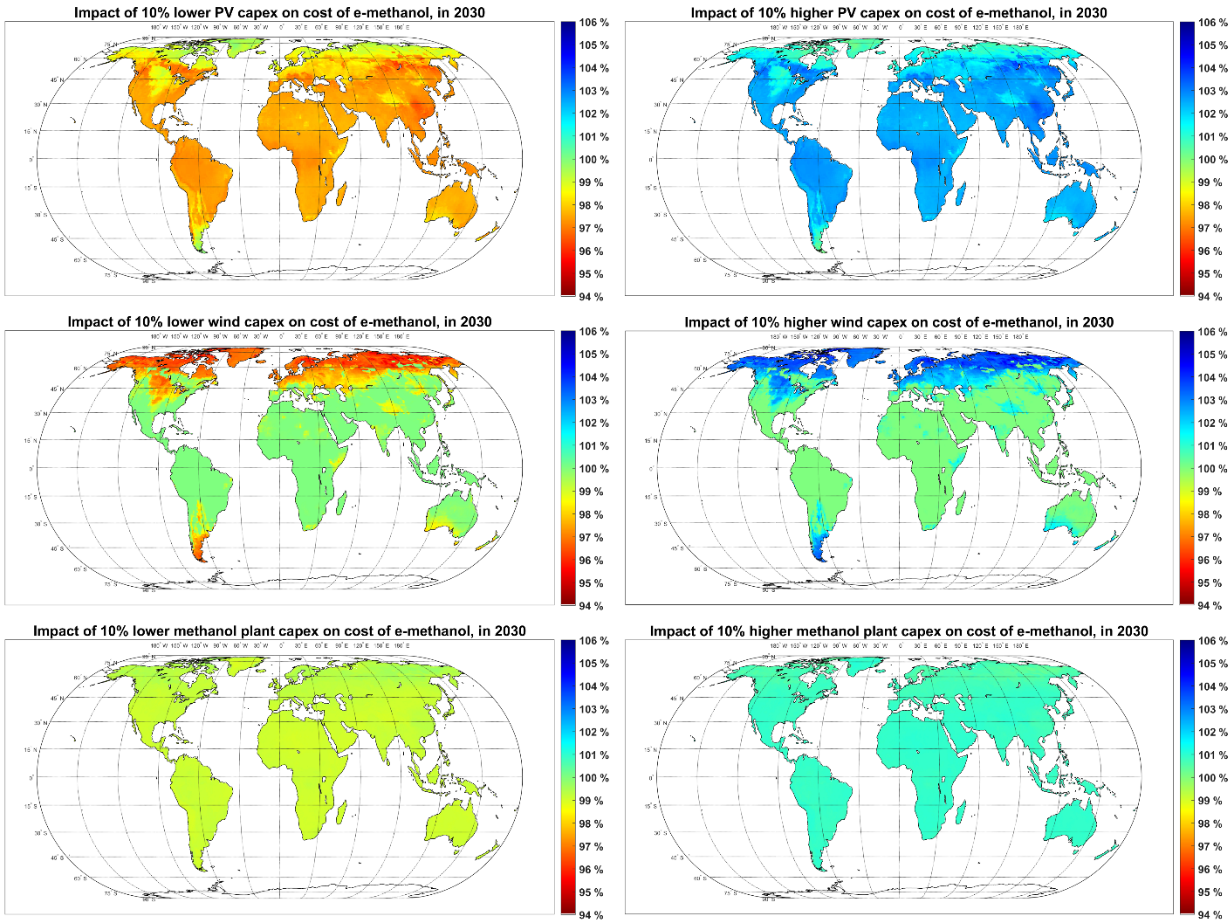

Fig. S21. Impact of 10% change in the capex and fixed opex of solar PV (top), wind power (centre) and methanol plants (bottom) on levelised cost of e-methanol *Onsite* in 2030.

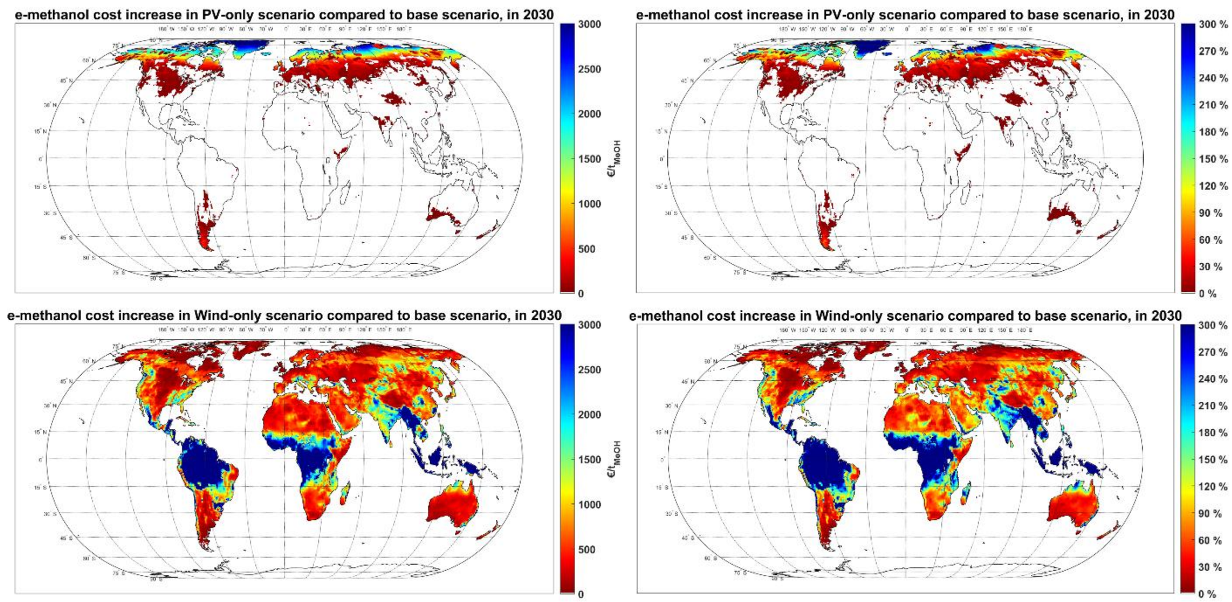

Fig. S22. Impact of PV-only (top) and wind-only (bottom) power scenarios on the levelised cost of e-methanol compared to the optimised hybrid PV-wind system in 2030.

S7. Cost projection of alkaline water electrolyser

Capex of a cluster of alkaline water electrolysers in 2020:

- 28 MW_p (17.5 $MW_{H2,LHV}$) at 5 bara: 638 €/kW_p (confidential quote from a European supplier)
- 28 MW_p (17.5 $MW_{H2,LHV}$) at 30 bara: 732 €/kW_p (including cost of H_2 compressor)
- 250 MW_p (156.3 $MW_{H2,LHV}$) at 30 bara: 600 €/kW_p (based on scaling factors for electrolyser and H_2 compressor)

The cost development of alkaline water electrolysers, in Table S1, has been evaluated based on an assumed learning rate[9–12] and an S-curve deployment of operational capacity of water and chlor-alkali electrolysers for a supply of 50% of required hydrogen for e-fuels[13] and e-chemicals[14] in a 100% renewable energy system by 2050.

Table S1. Capex development of alkaline water electrolyser.

		2020	2025	2030	2035	2040	2045	2050
Water and chlor-alkali electrolysers								
Operational capacity	GW_{el}	30	124	499	1 558	3 658	6 668	9 980
Newly installed capacity	GW_{el}	6.6	93	375	1 060	2 099	3 011	3 319
Cumulative installed capacity	GW_{el}	52	145	520	1 580	3 679	6 689	10 008
Water electrolysers - 250 MW_p at 30 bara								
Learning rate	%	18	18	17	17	16	16	15
Capex	€/kW_{el}	600	446	316	234	189	163	148

S8. Energy and cost projection of solid sorbent Direct Air Capture

The current and projected electrical and thermal energy demand of low temperature solid sorbent DAC technologies varies significantly in the literature, as shown in Table S2. The list includes data published over time by Climeworks (the only company with commercial scale solid sorbent DAC plants), recent academic literature, and a potential range of energetic demands by the National Academies of Sciences, Engineering, and Medicine.

Table S2. Energy demand of solid sorbent DAC plants in the literature.

	electricity demand	heat demand	Comment
	kWh_{el}/t_{CO2}	kWh_{th}/t_{CO2}	
Climeworks factsheet (2018)[15]	700	2200	including electricity demand for carbon storage process
Beuttler et al. (2019)[16]	400	1600	long-term projections by Climeworks for DACCS
Climeworks website FAQ (2021)[17]	650	2000	accessible via https://archive.org/web/
Deutz and Bardow (2021)[18]	700	3300	based on Climeworks' Artic Fox unit in Iceland
	500	1500	future target values
Climeworks (2023)[19]	direct number not available		Climeworks' next generation technology is expected to halve the energy demand compared to the Orca plant
National Academies of Sciences, Engineering, and Medicine (2019)[20]	22	514	best scenario – a scenario that may be unachievable
	156	944	low scenario
	315	1333	high scenario
Sabatino et al. (2021)[21]	80–160	1000–2500	based on several sorbents and different isotopes of CO_2 and water (excluding outlying data)
Sendi et al. (2022)[22]	250	1930	CO_2 capture at 20 °C and 50% relative humidity, and CO_2 compression to 150 bar
	160	1930	excluding approximate electricity demand for CO_2 compression to 150 bar
Wiegner et al. (2022)[23]	329–347	1704–1820	CO_2 capture at 20 °C and 75% relative humidity (excluding outlying data)

Reliable data on investment cost of solid sorbent DAC plants based on actual plants is scarce. In this study, the current and near future energy demand and capex of low-temperature solid sorbent DAC are based on Climeworks' current and next generation plants (Table S3). With 4000 t_{CO2} per year capacity, the Orca plant in Iceland is Climeworks' largest solid sorbent DAC plant operational since 2021. The capex of the Orca plant for carbon capture and sequestration is reported at 10−15 mUSD[24]. We consider an average of 12.5 mUSD for carbon capture only (excluding the sequestration process) with a long-term USD/€ exchange rate of 1.2. So far, the average energy consumption of the Orca plant has not been disclosed. However, it has been mentioned that the Orca plant has not been optimised for energy efficiency. Thus, we estimate its electricity demand to be same as earlier plants at 700 kWh/t_{CO2}, and its heat demand at 3000 kWh_{th}/t_{CO2}, considering some improvements compared to the heat demand of the Artic Fox DAC unit. Climeworks next project (Mammoth) is based on the same technology as the Orca plant and is expected to become operational in 2024. Regardless of 9 times larger capacity compared to Orca, Climeworks expects similar capex for the Mammoth plant. This is because addressing the problems identified during the operation of the Orca plant increases the capex of the Mammoth plant that offsets the benefit of the economy of scale. In the Direct Air Capture Summit 2023[19], Climeworks revealed that their next project after Mammoth would be based on their next generation technology and about 10 times larger. The next generation technology is reported to have two times higher output density, leading to a scaling factor of 0.7 for a 10 times larger plant compared to the Mammoth plant. The next generation technology is also reported to reduce the energy demand by 50% compared to the Orca and Mammoth plants[19]. Since Climeworks has not distinguished the electrical and thermal efficiency gains, we consider the same reduction rate for both. Nevertheless, both electrical and thermal energy demand remain within the feasible range in the literature.

Table S3. Specifications of Climeworks' current and near future DAC plants.

Project name	Unit	Orca	Mammoth	Next generation technology	comment
Year		2021	2024	~2027	
Capacity	kt_{CO2}/a	4	36	360	
Full load hours	h	8000	8000	8000	self-assumption
Capital cost	M€	10.4	93.7	564	
Capex	€/t_{CO2}·a	2378	2378	1192	
	€/kg_{CO2}·h	20,833	20,833	10,441	
Electricity demand	kWh_{el}/t_{CO2}	700	700	350	self-estimation
LT heat demand	kWh_{th}/t_{CO2}	3000	3000	1500	self-estimation

According to the International Energy Agency (IEA), a total of 1.85 Mt_{CO2}/a of solid sorbent DAC projects are already at different stages for deployment by 2027[25]. We then consider a S-curve development of the operational capacity of solid sorbent DAC to 2.5 Gt_{CO2}/a by 2050 (Table S4), well below estimations for required DAC capacity by mid-century[26]. The capex and energy demand of DAC in 2028−2050 are then calculated based on the cumulative installed capacity of

DAC at each time-step and the respective learning rates. A capex learning rate of 10−18% and an energy consumption learning rate of up to 10% are often considered for modular low-temperature solid sorbent DAC plants[19,27]. In this study, a learning rate of 12% and 4% are considered for capex and energy demand of low-temperature DAC, respectively. As such, the projected electricity and heat demand of DAC plants in 2050 (Table S4) remain well above the "low scenario" by the National Academies of Sciences, Engineering, and Medicine provided in the Table S2. Young et al.[27] report on a sorbent cost or 37 USD/t_{CO2} and a learning rate of 10−18% learning rate. A learning rate of 10% for the sorbent is used in this study.

Table S4. Projected long-term specifications of DAC plants.

	Unit	2020/21	2024/25	2027	2030	2035	2040	2045	2050
Cumulative capacity	Mt_{CO2}/a	-	-	1.85	15	110	550	1375	2500
Unit capacity	kt_{CO2}/a	4	36	360	360	360	360	360	360
Capex	€/t_{CO2}·a	2378	2378	1192	810	561	417	352	315
	€/kg_{CO2}·h	20,833	20,833	10,441	7096	4914	3653	3084	2759
Electricity demand	kWh_{el}/t_{CO2}	700	700	350	309	275	250	237	229
LT heat demand	kWh_{th}/t_{CO2}	3000	3000	1500	1326	1179	1072	1016	981
Sorbent cost	€/t_{CO2}	31	31	25.4	18.5	13.7	10.7	9.3	8.5

S9. Detailed installed capacities and annual flows of all components in 7 sample locations.

Table S5. Location of seven sample sites for e-methanol plants.

Abbreviation	CHL-PAT	AUS	US-CA	CHL-ATA	DEU	FIN	OMN
Location	Chile - Patagonia	Australia	US - California	Chile - Atacama	Germany	Finland	Oman
[Lat, Lon]	[-52.65, -72.45]	[-18.9, 123.75]	[35.1, -117]	[-23.85, -69.3]	[54, 12.6]	[63.45, 22.5]	[22.05, 58.95]

Table S6. Installed capacities of Power-to-Methanol plants for a 1 Mt/a methanol supply in 2030.

Item	Unit	CHL-PAT	AUS	US-CA	CHL-ATA	DEU	FIN	OMN
PV fixed tilted	MW	17.6	0.0	7 393.6	2 390.6	3 339.2	509.1	660.0
PV single-axis tracking	MW	0.0	6 041.0	0.0	3 458.0	369.7	3 301.1	5 886.2
Wind PP	MW	2 346.1	0.0	127.5	0.0	2 443.2	2 688.6	0.0
H_2-CCGT	MW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H_2-OCGT	MW	19.8	0.0	0.0	0.0	16.0	0.0	0.0
Battery interface	MW	0.0	343.5	278.0	321.9	53.8	68.3	374.4
Battery storage	MWh	0.1	1 731.9	1 024.1	1 384.8	231.5	279.9	1 517.2
Electrolyser	$MW_{H2,HHV}$	1 454.0	2 536.5	2 674.6	2 386.7	1 705.7	1 764.8	2 402.1
H_2 compressor	$MW_{H2,HHV}$	456.9	1 632.2	1 739.4	1 411.6	786.1	766.2	1 435.0
H_2 salt cavern	$MWh_{H2,HHV}$	0.0	391 720.6	0.0	0.0	391 456.8	0.0	0.0
H_2 rock cavern	$MWh_{H2,HHV}$	178 597.6	0.8	0.0	0.0	0.0	0.0	0.0
H_2 underground pipe	$MWh_{H2,HHV}$	1 227.0	0.1	15 268.8	13 581.1	0.1	65 858.4	13 776.4
DAC	t_{CO2}/h	203.0	184.3	210.6	203.0	188.1	200.0	197.7
CO_2 compressor	t_{CO2}/h	7.1	0.0	0.0	0.0	0.0	0.0	0.0
CO_2 liquefaction	t_{CO2}/h	4.4	0.0	3.2	0.0	0.6	12.0	0.5
CO_2 (g) storage	t_{CO2}	131.4	0.0	0.1	0.1	0.0	0.0	0.0
CO_2 (l) storage	t_{CO3}	2 115.2	0.2	2 977.6	1.3	872.5	7 520.5	475.7
Heat pump	MW_{th}	260.9	212.7	155.8	155.4	247.1	262.1	187.5
Electric water boiler	MW_{th}	136.3	179.3	568.9	398.0	243.5	173.9	308.1
LT (78°C) heat storage	MWh_{th}	2 769.4	2 639.9	1 724.0	1 940.3	3 133.8	3 369.7	2 325.5
HT (100°C) heat storage	MWh_{th}	912.8	1 039.3	3 153.1	2 031.3	1 672.1	1 404.0	1 658.1
Methanol plant	t_{MeOH}/h	139.2	126.3	145.6	139.0	128.4	139.8	135.6
MeOH storage	t_{MeOH}	39 592.2	5 941.9	71 040.9	50 569.0	12 297.7	35 844.0	40 357.3

Table S7. Annual flows of Power-to-Methanol plants for a 1 Mt/a methanol supply in 2030.

Item	Unit	CHL-PAT	AUS	US-CA	CHL-ATA	DEU	FIN	OMN
PV fixed tilted	GWh	12.2	0.0	12866.2	4816.1	3230.0	499.1	1116.3
PV single-axis tracking	GWh	0.0	12386.0	0.0	8146.3	384.7	3659.9	11750.4
Wind PP	GWh	11886.0	0.0	331.2	0.0	8482.4	8756.1	0.0
H_2-CCGT	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H_2-OCGT	GWh	4.6	0.0	0.0	0.0	3.6	0.0	0.0
Battery interface	GWh_{in}	0.0	632.2	326.9	505.1	44.1	43.7	553.9
Battery storage	GWh_{out}	0.0	588.0	304.0	469.7	41.0	40.6	515.1
Curtailed electricity	GWh	34.4	489.5	797.8	576.1	356.1	1015.5	731.9
Electrolyser	$GWh_{H2,HHV}$	7854.8	7843.0	7843.0	7843.0	7852.3	7843.0	7843.0
Replaced stack	$GWh_{H2,HHV}$	3202.1	0.0	0.0	205.6	2394.1	2195.6	156.2
H_2 compressor	$GWh_{H2,HHV}$	1659.1	4509.2	4177.0	4233.9	2270.8	2191.0	4281.9
H_2 salt cavern	$GWh_{H2,HHV}$	0.0	4509.2	0.0	0.0	2270.8	0.0	0.0
H_2 rock cavern	$GWh_{H2,HHV}$	1547.5	0.0	0.0	0.0	0.0	0.0	0.0
H_2 underground pipe	$GWh_{H2,HHV}$	111.6	0.1	4177.0	4233.9	0.0	2191.0	4281.9
DAC	kt_{CO2}	1460.0	1460.0	1460.0	1460.0	1460.0	1460.0	1460.0
CO_2 compressor	kt_{CO2}	10.6	0.0	0.0	0.0	0.0	0.0	0.0
CO_2 liquefaction	kt_{CO2}	19.2	0.0	12.6	0.0	5.2	34.9	2.6
CO_2 (g) storage	kt_{CO2}	10.6	0.0	0.0	0.0	0.0	0.0	0.0
CO_2 (l) storage	kt_{CO2}	19.2	0.0	12.6	0.0	5.2	34.9	2.6
Heat pump	GWh_{th}	1467.0	1566.1	844.2	876.1	1658.5	1429.4	1226.3
Electric water boiler	GWh_{th}	470.6	375.5	1105.2	1071.2	282.2	509.8	718.1
LT (78°C) heat storage	$GWh_{th,in}$	1069.9	1142.0	615.7	639.0	1209.5	1042.6	894.3
HT (100°C) heat storage	$GWh_{th,in}$	75.8	269.0	636.1	542.4	223.6	148.5	404.2
Methanol plant	kt_{MeOH}	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0
Methanol storage	kt_{MeOH}	74.4	8.3	87.0	63.4	22.8	68.8	52.1

S10. Input data

Table S8. Technical and financial specifications of applied technologies.

	units	2020	2025	2030	2035	2040	2045	2050	Ref.
Global unified WACC	%	7	7	7	7	7	7	7	
PV fixed tilted power plant									
Capex	€/kW_p	580	466	390	337	300	270	246	[28]
	€/kW_p	432	336	278	237	207	184	166	[29]
	€/kW_p	475	370	306	237	207	184	166	this study
Opex fix	€/kW_p	13.2		10.6		8.8		7.4	[28]
	€/kW_p	7.76		5.66		4.47	4.04	3.70	[29]
	€/kW_p	8.53	7.17	6.23	5.00	4.47	4.04	3.70	this study
Opex var	€/kWh_{el}	0	0	0	0	0	0	0	
Installation density	MW/km^2	91	100	109	118	127	137	137	based on [29,30]
Lifetime	year	30	35	35	35	40	40	40	[31]
PV single-axis tracking power plant									
Capex	€/kW_p	638	513	429	371	330	297	271	[28,32]
	€/kW_p	475	370	306	261	228	202	183	[29,32]
	€/kW_p	523	407	337	261	228	202	183	this study
Opex fix	€/kW_p	15		12		10		8	[28,32]
	€/kW_p	8.54		6.23		4.92		4.07	[29,32]
	€/kW_p	9.40	7.88	6.86	5.50	4.92	4.44	4.07	this study
Opex var	€/kWh_{el}	0	0	0	0	0	0	0	
Installation density	MW/km^2	62	69	75	81	87	94	94	based on [29,30]
Lifetime	year	30	35	35	35	40	40	40	
Wind power plant (onshore)									
Capex	€/kW_p	1150	1060	1000	965	940	915	900	
Opex fix	€/kW_p	23.0	21.2	20.0	19.3	18.8	18.3	18.0	
Opex var	€/kWh_{el}	0	0	0	0	0	0	0	
Lifetime	year	25	25	25	25	25	25	25	
Disturbance factor	%	8	8	8	8	8	8	8	
Battery pack (storage) - LFB									
Capacity	MWh	80	80	80	80	80	80	80	[29]
Capex	€/kWh	234	153	110	89	76	68	61	[29]
Opex fix	€/kWh	3.28	2.6	2.2	2.05	1.9	1.77	1.71	[29]
Opex var	€/kWh	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	

Lifetime	year	20	20	20	20	20	20	20	[33]
Cycle eff.	%	91	92	93	94	95	95	95	[34]
Self-discharge	%/h	0	0	0	0	0	0	0	
Battery interface (inverter, etc)									
Capacity	MW	20	20	20	20	20	20	20	[29]
Capex	€/kW	117	76	55	44	37	33	30	[29]
Opex $_{fix}$	€/kW	1.64	1.29	1.10	1.01	0.93	0.86	0.84	[29]
Opex $_{var}$	€/kWh	0	0	0	0	0	0	0	
Lifetime	year	20	20	20	20	20	20	20	[33]
Combined cycle gas turbine									
Capacity	MW		580	580	580	580	580	580	[35]
Capex (conventional)	€/kW		775	775	775	775	775	775	[35]
Capex (H_2-fuelled)	€/kW		852.5	852.5	852.5	852.5	852.5	852.5	10% higher
Opex $_{fix}$	% of capex p.a.		2.5	2.5	2.5	2.5	2.5	2.5	[35]
Opex $_{var}$	€/kWh		0.002	0.002	0.002	0.002	0.002	0.002	[35]
Lifetime	year		35	35	35	35	35	35	[36]
Efficiency	% - LHV		61.2	61.2	62.3	63.3	63.3	63.3	[35]
Efficiency	% - HHV		52.2	52.2	53.1	54.0	54.0	54.0	
Open cycle gas turbine									
Capacity	MW		250	250	250	250	250	250	[35]
Capex (conventional)	€/kW		475	475	475	475	475	475	[35]
Capex (H_2-fuelled)	€/kW		522.5	522.5	522.5	522.5	522.5	522.5	10% higher
Opex $_{fix}$	% of capex p.a.		3.0	3.0	3.0	3.0	3.0	3.0	[35]
Opex $_{var}$	€/kWh		0.011	0.011	0.011	0.011	0.011	0.011	[35]
Lifetime	year		35	35	35	35	35	35	[36]
Efficiency	% - LHV		43.8	45.4	45.9	46.5	47.0	47.5	
Efficiency	% - HHV		37.4	38.7	39.2	39.6	40.1	40.5	[35]
Alkaline water electrolyser									[37–39] and LR
Capacity	MW	250	250	250	250	250	250	250	
Capex (BCS)	€/kW_{el}	600	446	316	234	189	163	148	
	€/$kW_{H2,HHV}$	818	597	415	301	239	202	180	
Capex (HCS)	€/kW_{el}	792	659	495	373	303	261	238	
	€/$kW_{H2,HHV}$	1080	882	649	480	383	324	290	
Opex $_{fix}$	% of capex p.a.	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
Opex $_{var}$ – excl. stack replacement cost	€/$kWh_{H2,HHV}$	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
Opex $_{var}$ – stack replacement cost (BCS)	€/$kWh_{H2,HHV}$	0.0019	0.0014	0.0011	0.0009	0.0009	0.0009	0.0009	

Opex $_{var}$ – stack replacement cost (HCS)	€/kWh$_{H2,HHV}$	0.0030	0.0023	0.0018	0.0015	0.0015	0.0015	0.0015	
Lifetime - system	year	30	30	30	30	30	30	30	
Lifetime - stack	hours	80 000	88 000	96 000	104 000	112 000	120 000	128 000	
Availability (single stack)	%	95	95	95	95	95	95	95	
Availability (system level)	%	100	100	100	100	100	100	100	
PtH$_2$ eff. - overall	% - LHV	62.5	63.8	65.0	66.3	67.5	68.8	70.0	
PtH$_2$ eff. - overall	% - HHV	73.3	74.8	76.2	77.7	79.1	80.6	82.1	
PtHeat eff.	% - utilisable	22.7	21.4	20.0	18.7	17.3	16.0	14.7	
Heat temperature	°C	75	75	75	75	75	75	75	
H_2 pressure	bar	30	30	30	30	30	30	30	
H_2 compressor (multi-stage)									
Compression range	bar	30→150	30→150	30→150	30→150	30→150	30→150	30→150	[40]
Capacity	MW	2.0	2.0	4.0	4.0	4.0	4.0	4.0	
	MW$_{H2,HHV}$	80	80	160	160	160	160	160	
Capex	€/kW	2 500	2 500	1 900	1 900	1 900	1 900	1 900	[41]
	€/kW$_{H2,HHV}$	63	63	48	48	48	48	48	
Opex $_{fix}$	% of capex p.a.	4.0	4.0	4.0	4.0	4.0	4.0	4.0	[42]
Opex $_{var}$	€/kWh$_{H2,HHV}$	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	
Lifetime	year	20	20	20	20	20	20	20	[43]
Electricity consumption	kWh$_{el}$/kWh$_{H2,HHV}$	0.025	0.025	0.025	0.025	0.025	0.025	0.025	[44]
	kWh$_{el}$/kg$_{H2}$	0.99	0.99	0.99	0.99	0.99	0.99	0.99	
Mass eff.	%	100	100	100	100	100	100	100	
Hydrogen storage - man-made salt cavern									
Working capacity	tonne H_2	2 000	2 000	4 000	4 000	4 000	4 000	4 000	[40]
	GWh$_{H2,HHV}$	79	79	158	158	158	158	158	
Capex - excluding cushion gas cost	€/kg$_{H2\text{ - working capacity}}$	16.4	16.4	13.3	13.3	13.3	13.3	13.3	[40]
(scaling factor: 0.7)	€/kWh$_{H2,HHV}$	0.416	0.416	0.338	0.338	0.338	0.338	0.338	
Levelised cost of H_2 for cushion gas (global average)	€/kWh$_{H2,HHV\text{ - produced}}$	0.071	0.053	0.042	0.031	0.027	0.023	0.020	based on [44]
Cushion gas cost	€/kWh$_{H2,HHV\text{ - working capacity}}$	0.032	0.024	0.019	0.015	0.012	0.011	0.009	
(cushion/total capacity: 0.3)									
Capex - including cushion gas cost	€/kg$_{H2\text{ - working capacity}}$	15.3	15.0	14.8	14.6	14.5	14.5	14.4	
	€/kWh$_{H2,HHV}$	0.389	0.381	0.375	0.371	0.369	0.367	0.366	
Opex $_{fix}$	% of capex p.a.	4	4	4	4	4	4	4	[43]
Opex $_{var}$	€/kWh$_{H2,HHV}$	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	
Lifetime	year	30	30	30	30	30	30	30	[43]
Cycle eff.	%	100	100	100	100	100	100	100	

Self-discharge	%/h	0	0	0	0	0	0	0	
Maximum charge rate	%/day	10	10	10	10	10	10	10	[45]
Minimum Energy/Power ratio	h	240	240	240	240	240	240	240	[45]
Pressure range	bar	43-150	43-150	43-150	43-150	43-150	43-150	43-150	[40]
Hydrogen storage - lined rock cavern									
Working capacity	tonne H_2	500	500	1000	1000	1000	1000	1000	[40]
	$GWh_{H2,HHV}$	20	20	39	39	39	39	39	
Capex	€/kg_{H2}	56.9	56.9	49.5	49.5	49.5	49.5	49.5	[40]
(scaling factor: 0.8)	€/$kWh_{H2,HHV}$	1.44	1.44	1.25	1.25	1.25	1.25	1.25	
Opex $_{fix}$	% of capex p.a.	4	4	4	4	4	4	4	
Opex $_{var}$	€/$kWh_{H2,HHV}$	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	
Lifetime	year	30	30	30	30	30	30	30	
Cycle eff.	%	100	100	100	100	100	100	100	
Self-discharge	%/h	0	0	0	0	0	0	0	
Maximum charge rate	%/day	10	10	10	10	10	10	10	
Minimum Energy/Power ratio	h	240	240	240	240	240	240	240	
Pressure range	bar	20-150	20-150	20-150	20-150	20-150	20-150	20-150	[40]
Hydrogen storage - underground pipe									
Working capacity	tonne H_2	25	25	50	50	50	50	50	[37]
	$GWh_{H2,HHV}$	1.0	1.0	2.0	2.0	2.0	2.0	2.0	
Capex	€/kg_{H2}	493	493	483	483	483	483	483	[40]
(scaling factor: 0.97)	€/$kWh_{H2,HHV}$	12.50	12.50	12.25	12.25	12.25	12.25	12.25	
Opex $_{fix}$	% of capex p.a.	1	1	1	1	1	1	1	[37]
	€/$kWh_{H2,HHV}$	0.13	0.13	0.12	0.12	0.12	0.12	0.12	
Opex $_{var}$	€/kWh_{H2}	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	
Lifetime	year	30	30	30	30	30	30	30	
Cycle eff.	%	100	100	100	100	100	100	100	
Self-discharge	%/h	0	0	0	0	0	0	0	
Minimum Energy/Power ratio	h	6	6	6	6	6	6	6	[46]
Maximum charge rate	%/h	16.67	16.67	16.67	16.67	16.67	16.67	16.67	[46]
Pressure range	bar	8-100	8-100	8-100	8-100	8-100	8-100	8-100	[37]
MeOH Synthesis Plant – including methanol synthesis unit, distillation unit and 30 days emergency MeOH storage									
Capacity	Mt_{MeOH}/a	0.5	0.5	1	1	2	2	3	
Capex *(scaling factor: 0.78)*	€/kg_{MeOH}·h	4 598	4 598	3 947	3 947	3 389	3 389	3 100	based on[47] and SF
Opex $_{fix}$	% of capex p.a.	4	4	4	4	4	4	4	
Opex $_{var}$	€/t_{MeOH}	11	11	11	11	11	11	11	[48]

Lifetime	year	30	30	30	30	30	30	30	
H_2 consumption	t_{H2}/t_{MeOH}	0.199	0.199	0.199	0.199	0.199	0.199	0.199	[48]
CO_2 consumption	t_{CO2}/t_{MeOH}	1.46	1.46	1.46	1.46	1.46	1.46	1.46	[48]
Electricity consumption	kWh/t_{MeOH}	169	169	169	169	169	169	169	[48]
Minimum load	% of full capacity	50%	50%	50%	50%	50%	50%	50%	
Ramp-up rate (min load to max)	% per hr	2%	2%	2%	2%	2%	2%	2%	
Ramp-down rate (max to min load)	% per hr	20%	20%	20%	20%	20%	20%	20%	
Ramp-up/down cost	$€/\Delta t_{MeOH}/h$	2	2	2	2	2	2	2	
Availability	h	8000	8000	8000	8000	8000	8000	8000	
Methanol storage									[49]
Capacity (*scaling factor: 0.78)*	kt	42	42	83	83	167	167	250	
Capex	€/t	71	71	61	61	52	52	48	
Opex $_{fix}$	% of capex p.a.	4	4	4	4	4	4	4	
Opex $_{var}$	€/t	1	1	1	1	1	1	1	
Minimum Energy to Power ratio	-	168	168	168	168	168	168	168	
Lifetime	year	30	30	30	30	30	30	30	
NH_3 Plant - including N_2 & H_2 compressors, Air Separation Unit, N_2 buffer, ammonia synthesis unit and 30 days emergency NH_3 storage									[2,7]
Capex at 1 Mt_{NH3}/a capacity	$€/kg_{NH3}\cdot h$	5259	5 259	5 259	5 259	5 259	5 259	5 259	
Opex $_{fix}$	% of capex p.a.	4.0	4.0	4.0	4.0	4.0	4.0	4.0	
Opex $_{var}$	$€/t_{NH3}$	11	11	11	11	11	11	11	
Lifetime	year	30	30	30	30	30	30	30	
Electricity consumption	kWh/t_{NH3}	738	738	738	738	738	738	738	
H_2 consumption	kg_{H2}/t_{NH3}	179.3	179.3	179.3	179.3	179.3	179.3	179.3	
N_2 consumption	kg_{N2}/t_{NH3}	830.9	830.9	830.9	830.9	830.9	830.9	830.9	
Excess heat generation (T>100 °C)	$kWhth/t_{NH3}$	1129	1129	1129	1129	1129	1129	1129	[8]
Minimum load	% of full capacity	50	50	50	50	50	50	50	
Ramp-up time (min to max load)	% per hr	2	2	2	2	2	2	2	
Ramp-down time (max to min load)	% per hr	20	20	20	20	20	20	20	
Ramp-up/down cost	$€/\Delta t_{NH3}/h$	2	2	2	2	2	2	2	
Availability	h	8000	8000	8000	8000	8000	8000	8000	
Pressure	bar	150	150	150	150	150	150	150	
H_2 & N_2 conversion rate	%	99	99	99	99	99	99	99	
NH_3 storage									[2,7]
Capacity	kt_{NH3}	82	82	82	82	82	82	82	
Capex (via 0.8 scaling factor)	$€/t_{NH3}$	590	590	590	590	590	590	590	
Opex $_{fix}$	% of capex p.a.	4	4	4	4	4	4	4	

Opex $_{var}$	€/t_{NH3}	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
Lifetime	year	30	30	30	30	30	30	30	
Cycle eff.	%	100	100	100	100	100	100	100	
Self-discharge	%/h	0	0	0	0	0	0	0	
Low-Temperature CO_2 Direct Air Capture at 1 bar									Section S7
Capacity	kt_{CO2}/a	4	36	360	360	360	360	360	
	t_{CO2}/h	0.5	4.5	45	45	45	45	45	
Capex	€/t_{CO2}·a	2378	2378	810	561	417	352	315	
	€/kg_{CO2}·h	20,833	20,833	7096	4914	3653	3084	2759	
Opex $_{fix}$	% of capex p.a.	4.0	4.0	4.0	4.0	4.0	4.0	4.0	
Opex $_{var}$ - sorbent	€/t_{CO2}	31	31	18.5	13.7	10.7	9.3	8.5	
Opex $_{var}$ - other	€/t_{CO2}	1	1	1	1	1	1	1	
Lifetime	year	20	25	25	30	30	30	30	
Availability	%	95	95	95	95	95	95	95	
Output pressure	bara	1	1	1	1	1	1	1	
Electricity demand	kWh_{el}/t_{CO2}	700	700	309	275	250	237	229	
LT heat demand	kWh_{th}/t_{CO2}	3000	3000	1326	1179	1072	1016	981	
Heat temperature	°C	100	100	100	100	100	100	100	
CO_2 Compressor									
Pressure range	bara	1→50	1→50	1→50	1→50	1→50	1→50	1→50	
Electricity consumption (multi-stage)	kWh/t_{CO2}	99	99	99	99	99	99	99	[50]
Unit capacity	t_{CO2}/h	10	10	10	10	10	10	10	
	kW_{el}	990	990	990	990	990	990	990	
Capex	€/kW_{el}	3 415	3 415	3 415	3 415	3 415	3 415	3 415	[41]
	€/kg_{CO2}·h	338	338	338	338	338	338	338	
Opex $_{fix}$	% of capex p.a.	4.0	4.0	4.0	4.0	4.0	4.0	4.0	
Opex var (excl. el.)	€/t_{CO2}	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Lifetime	year	20	20	20	20	20	20	20	
CO_2 liquefaction plant									expert's opinion
Unit capacity	t_{CO2}/h	10	10	10	10	10	10	10	
Feed gas pressure	bar	1	1	1	1	1	1	1	
Capex *(scaling factor: 0.78)*	€/kg_{CO2}·h	1 430	1 430	1 430	1 430	1 430	1 430	1 430	
Opex fix	% of capex p.a.	4.0	4.0	4.0	4.0	4.0	4.0	4.0	
Opex var (excl. el.)	€/t_{CO2}	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Lifetime	year	20	20	20	20	20	20	20	
Electricity consumption (from 5 bara)	kWh/t_{CO2}	160	160	160	160	160	160	160	

Ramp-up time	% per hour	100	100	100	100	100	100	100	
CO_2 (g) Storage									[37]
Unit capacity	t_{CO2}	1 600	1 600	1 600	1 600	1 600	1 600	1 600	
Operating pressure range	bar	20-50	20-50	20-50	20-50	20-50	20-50	20-50	
Capex	€/t_{CO2}	22 000	22 000	22 000	22 000	22 000	22 000	22 000	
Opex fix	% of capex p.a.	1.3	1.3	1.3	1.3	1.3	1.3	1.3	
Opex var	€/t_{CO2}	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Lifetime	year	30	30	30	30	30	30	30	
Cycle eff.	%	100	100	100	100	100	100	100	
Self-discharge	%/h	0	0	0	0	0	0	0	
CO_2 (l) Storage tank									[37]
Unit capacity	t_{CO2}	5600	5600	5600	5600	5600	5600	5600	
Capex	€/t_{CO2}	3 560	3 560	3 560	3 560	3 560	3 560	3 560	
Opex fix	% of capex p.a.	1.2	1.2	1.2	1.2	1.2	1.2	1.2	
Opex var	€/t_{CO2}	0.2	0.2	0.2	0.2	0.2	0.2	0.2	
Lifetime	year	30	30	30	30	30	30	30	
Cycle eff.	%	100	100	100	100	100	100	100	
Self-discharge	%/h	0	0	0	0	0	0	0	
Heat pump - electrical compression									[51]
Unit capacity	MWh_{th}	4	4	4	4	4	4	4	
Capex	€/kW_{th}	660	618	590	568	554	540	530	
Opex fix	€/kW_{th} p.a.	2	2	2	2	2	2	2	
Opex var	€/kWh_{th}	0.00180	0.00175	0.00170	0.00166	0.00163	0.00161	0.00160	
Lifetime	year	25	25	25	25	25	25	25	
COP (soure@40C, sink@78-100°C)	-	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
Availability	h	8000	8000	8000	8000	8000	8000	8000	
Electric water boiler									[52]
Unit capacity	MWh_{th}	15	15	15	15	15	15	15	
Capex	€/kW_{th}	70	65	60	60	60	60	60	
$Opex_{fix}$	% of capex p.a.	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
$Opex_{var}$	€/kWh_{th}	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	
Lifetime	year	25	25	25	25	25	25	25	
Efficiency	%	99	99	99	99	99	99	99	
Availability	%	99	99	99	99	99	99	99	
Low-Temperature Heat Storage (78 °C water storage) - utilised to 20 °C									
Unit capacity	tonne water	14 828	14 828	14 828	14 828	14 828	14 828	14 828	

	MWh_{th}	1 000	1 000	1 000	1 000	1 000	1 000	1 000	
Capex	€/t	777	777	777	777	777	777	777	[53]
	€/kWh_{th}	11.5	11.5	11.5	11.5	11.5	11.5	11.5	
Opex fix	% of capex p.a.	0.75	0.75	0.75	0.75	0.75	0.75	0.75	[54]
Opex var	€/kWh_{th}	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	
Lifetime	year	30	30	30	30	30	30	30	[54]
Cycle eff.	%	98.0	98.0	98.0	98.0	98.0	98.0	98.0	
Energy to power ratio	-	7	7	7	7	7	7	7	[53]
Self-discharge	%/day	0.12	0.12	0.12	0.12	0.12	0.12	0.12	[53]
Self-discharge	%/h	0.99995	0.99995	0.99995	0.99995	0.99995	0.99995	0.99995	
Med. Temperature Heat Storage (98 °C water storage) - utilised to 78 °C									
Unit capacity	tonne water	43 000	43 000	43 000	43 000	43 000	43 000	43 000	
	MWh_{th}	1 000	1 000	1 000	1 000	1 000	1 000	1 000	
Capex	€/t	628	628	628	628	628	628	628	[53]
	€/kWh_{th}	27.0	27.0	27.0	27.0	27.0	27.0	27.0	
Opex fix	% of capex p.a.	0.75	0.75	0.75	0.75	0.75	0.75	0.75	[54]
Opex var	€/kWh_{th}	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	
Lifetime	year	30	30	30	30	30	30	30	[54]
Cycle efficiency	%	98.0	98.0	98.0	98.0	98.0	98.0	98.0	self-assumption
Energy to power ratio	-	7	7	7	7	7	7	7	[53]
Self-discharge	%/day	0.12	0.12	0.12	0.12	0.12	0.12	0.12	[53]
Self-discharge	%/h	0.99995	0.99995	0.99995	0.99995	0.99995	0.99995	0.99995	

Table S9. Technical specifications of applied storage technologies.

Storage	Energy to Power Ratio - charge	Energy to Power Ratio - discharge	maximum hourly charge	maximum hourly discharge	Cycle eff.	Charging eff.	Discharging eff.	Self-discharge
	h	h	%/h	%/h	%	%	%	%/hour
Battery 2020	1	1	100.00%	100.00%	91%	95.4%	95.4%	0.000%
Battery 2030	1	1	100.00%	100.00%	93%	96.4%	96.4%	0.000%
Battery 2040	1	1	100.00%	100.00%	95%	97.5%	97.5%	0.000%
Battery 2050	1	1	100.00%	100.00%	95%	97.5%	97.5%	0.000%
H_2 salt cavern	240	240	0.42%	0.42%	100%	100.0%	100.0%	0.000%
H_2 rock cavern	240	240	0.42%	0.42%	100%	100.0%	100.0%	0.000%
H_2 underground pipe	6	6	16.67%	16.67%	100%	100.0%	100.0%	0.000%
CO_2 gaseous storage	6	6	16.67%	16.67%	100%	100.0%	100.0%	0.000%
CO_2 liquid storage	6	6	16.67%	16.67%	100%	100.0%	100.0%	0.000%
LT heat storage (warm water)	7	7	14.29%	14.29%	98%	99.0%	99.0%	0.005%
HT heat storage (hot water)	7	7	14.29%	14.29%	98%	99.0%	99.0%	0.005%
MeOH Storage	168	168	0.60%	0.60%	100%	100.0%	100.0%	0.000%

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