Energy Imports and Infrastructure in a Carbon-Neutral European Energy System

Fabian Neumann, **Tom Brown** (TU Berlin); Johannes Hampp (PIK)
t.brown@tu-berlin.de, Department of Digital Transformation in Energy Systems, TU Berlin

Ariadne AP6 Workshop, 8th April 2024

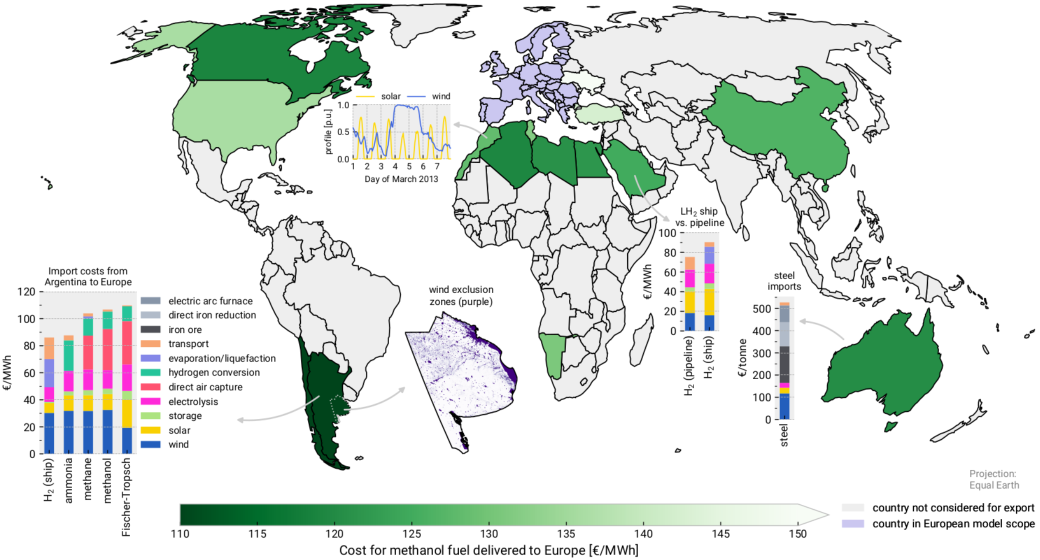
Table of Contents

Energy Imports and Infrastructure

Goals of paper

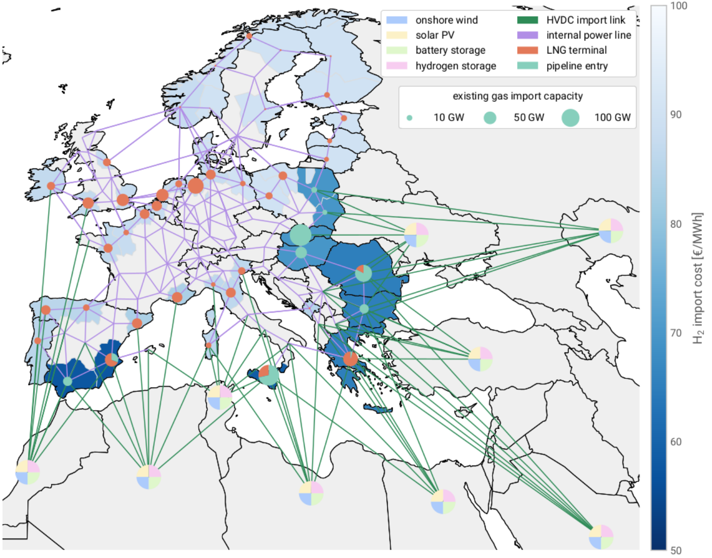
- Explore import of green energy to Europe: volumes, costs and network infrastructure
- Couple an energy system model of Europe with infrastructure (PyPSA-Eur) to global production cost model for green fuels and materials (TRACE)
- Green imports allowed from: hydrogen (pipeline and ship), ammonia, methane, methanol, Fischer-Tropsch products, steel
- Model is greenfield-ish to represent 2040-50 (path dependencies not modelled)
- Steel and basic chemicals industries allowed to move within Europe (e.g. to Spain)

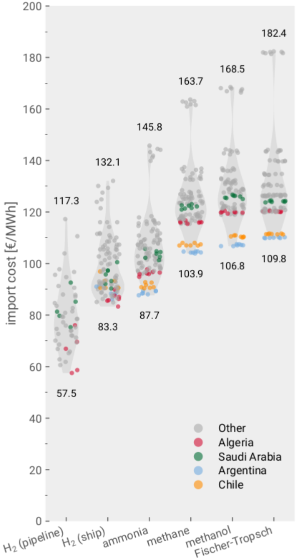
Energy imports global setup



Source: Neumann et al, 2024

Energy imports allowed routes

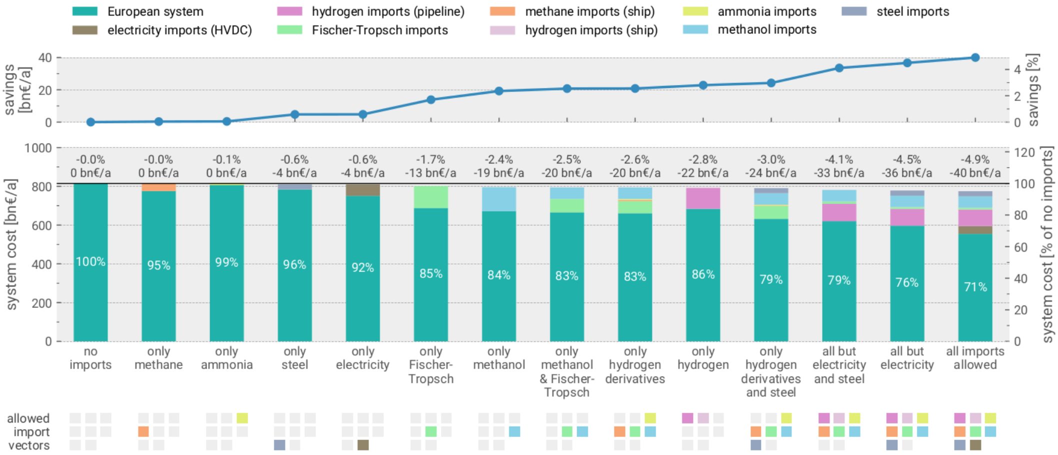




Source: Neumann et al, 2024

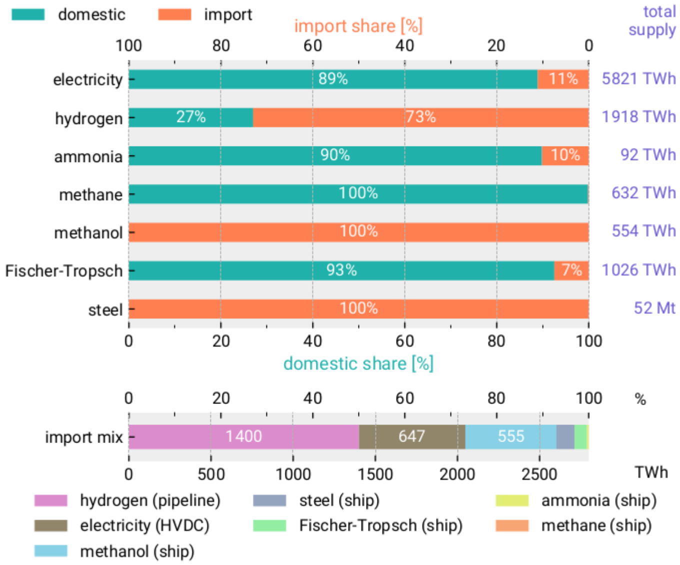
Impact of different imports on system costs

NB: Results **very sensitive** to inputs like electrolyser cost and WACC.



Source: Neumann et al, 2024

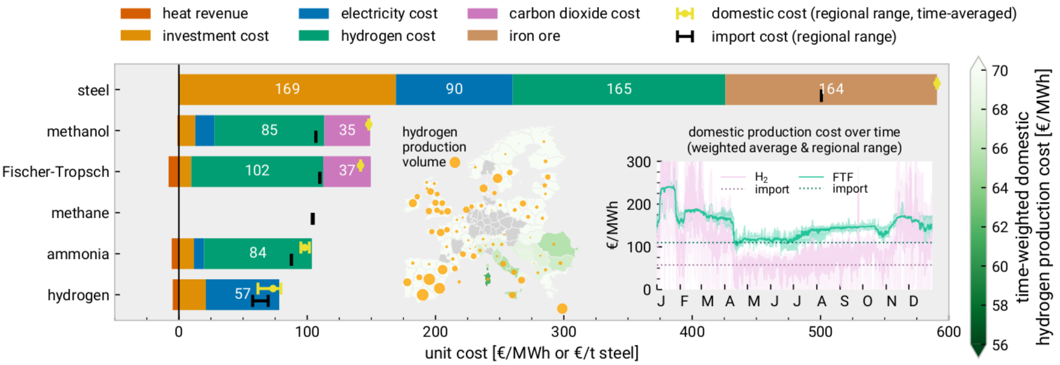
Energy imports distribution local-imported



Source: Neumann et al, 2024

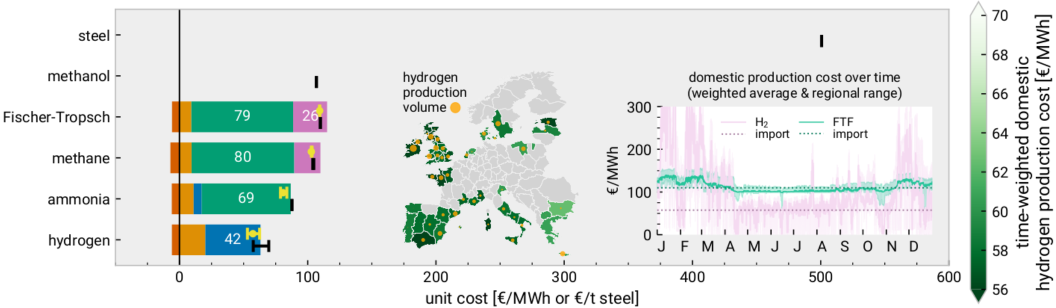
Production costs domestic versus imported for 'no imports'

NB: domestic and import costs very close for hydrogen and ammonia (since e.g. Spain in Europe competes with MENA); sales of waste heat provide revenue.



Source: Neumann et al, 2024

Production costs domestic versus imported for ‘all imports’



Source: Neumann et al, 2024

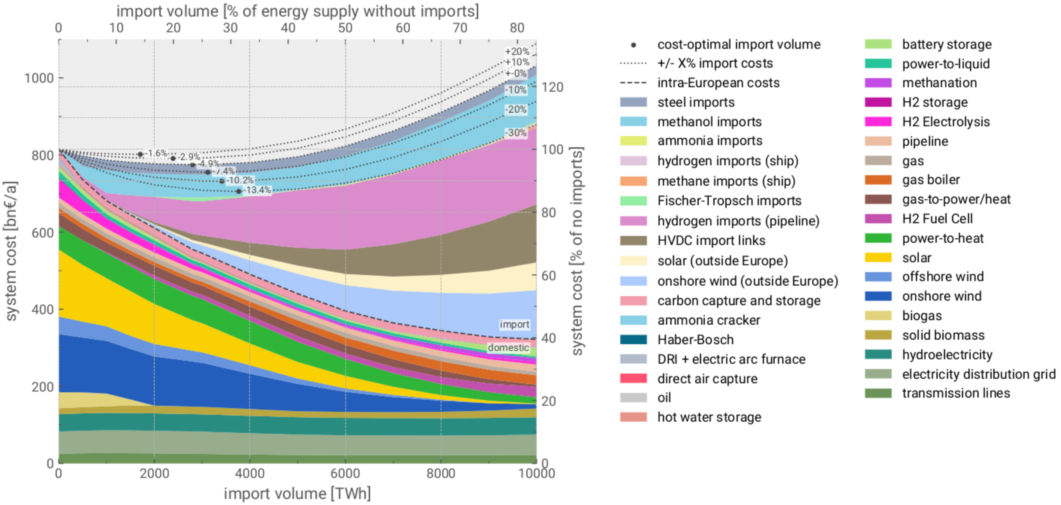
Cost sensitivity for Fischer-Tropsch fuels

Factor	Change	Unit	Change	Unit
higher WACC of 12% (e.g. high project risk)	+43.1	€/MWh	+39.3	%
higher WACC of 10% (e.g. high project risk)	+25.3	€/MWh	+23.0	%
higher WACC of 8% (e.g. high project risk)	+8.2	€/MWh	+7.4	%
higher direct air capture investment cost (+200%)	+55.8	€/MWh	+50.8	%
higher direct air capture investment cost (+100%)	+28.1	€/MWh	+25.6	%
higher direct air capture investment cost (+50%)	+14.1	€/MWh	+12.9	%
higher direct air capture investment cost (+25%)	+7.1	€/MWh	+6.5	%
higher electrolysis investment cost (+200%)	+29.2	€/MWh	+26.6	%
higher electrolysis investment cost (+100%)	+16.7	€/MWh	+15.2	%
higher electrolysis investment cost (+50%)	+9.0	€/MWh	+8.2	%
higher electrolysis investment cost (+25%)	+4.7	€/MWh	+4.3	%
Argentina and Chile not available for export	+10.1	€/MWh	+9.2	%
lower WACC of 3% (e.g. government guarantees)	-29.5	€/MWh	-26.8	%
lower WACC of 5% (e.g. government guarantees)	-15.5	€/MWh	-14.1	%
lower WACC of 6% (e.g. government guarantees)	-8.0	€/MWh	-7.2	%
sell excess curtailed electricity at 40 €/MWh	-24.7	€/MWh	-22.6	%
sell excess curtailed electricity at 30 €/MWh	-15.6	€/MWh	-14.2	%
sell excess curtailed electricity at 20 €/MWh	-8.0	€/MWh	-7.2	%
option to use available biogenic or cycled CO_2 for 60 €/t	-21.7	€/MWh	-19.7	%
option to use available biogenic or cycled CO_2 for 80 €/t	-16.1	€/MWh	-14.7	%
option to use available biogenic or cycled CO_2 for 100 €/t	-10.6	€/MWh	-9.7	%
option to build geological hydrogen storage at 2.4 €/kWh (reduction by 95%)	-8.2	€/MWh	-7.4	%
option to use power-to-X waste heat streams for direct air capture	-3.8	€/MWh	-3.4	%
highly flexible operation of fuel synthesis plant (20% minimum part-load instead of 70%)	-5.4	€/MWh	-4.9	%

Supplementary Table 1: **Examples for potential import cost increases or decreases.** The table presents cost sensitivities in absolute and relative terms based on the supply chain for producing Fischer-Tropsch fuels in Argentina for export to Europe. The reference fuel import cost for this case is 109.8 €/MWh. Responses to changes in the input assumptions are not additive.

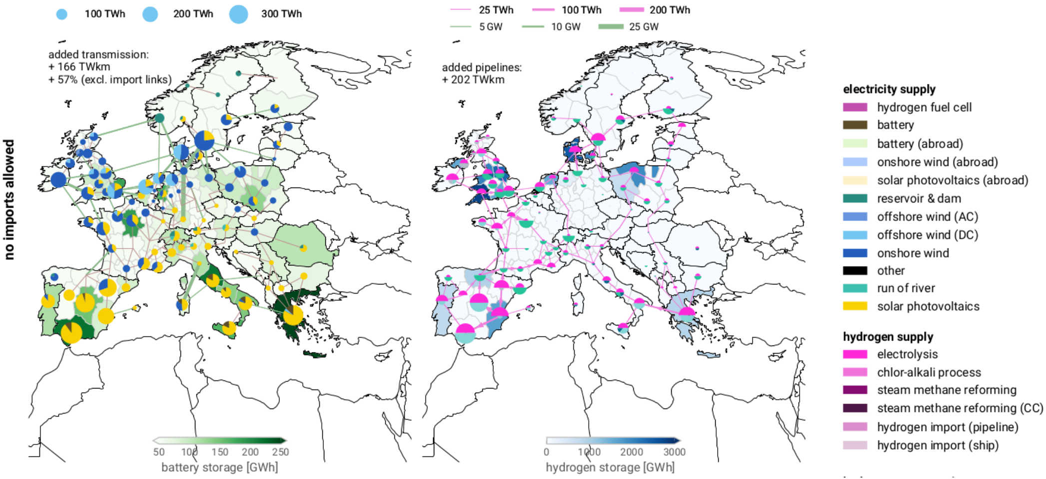
Source: Neumann et al, 2024

Energy imports sweep with cost sensitivities -30% to +20%



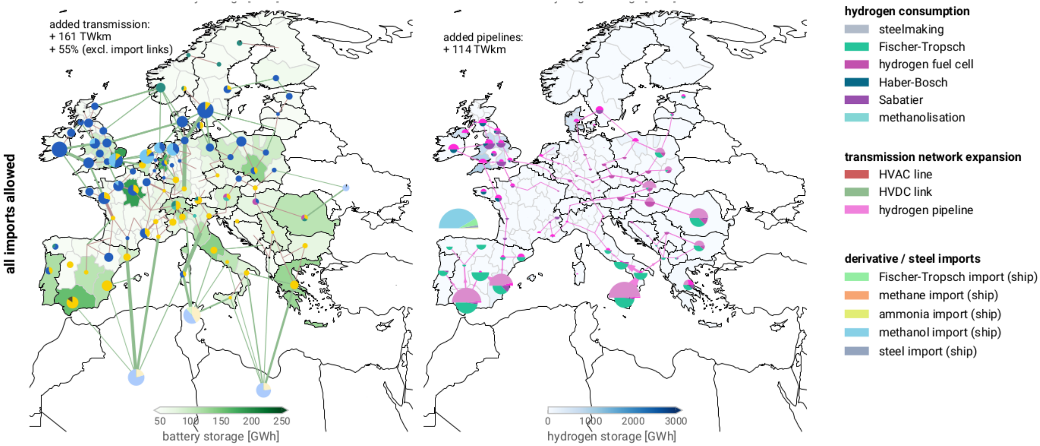
Source: Neumann et al, 2024

Energy infrastructure map for 'no imports'



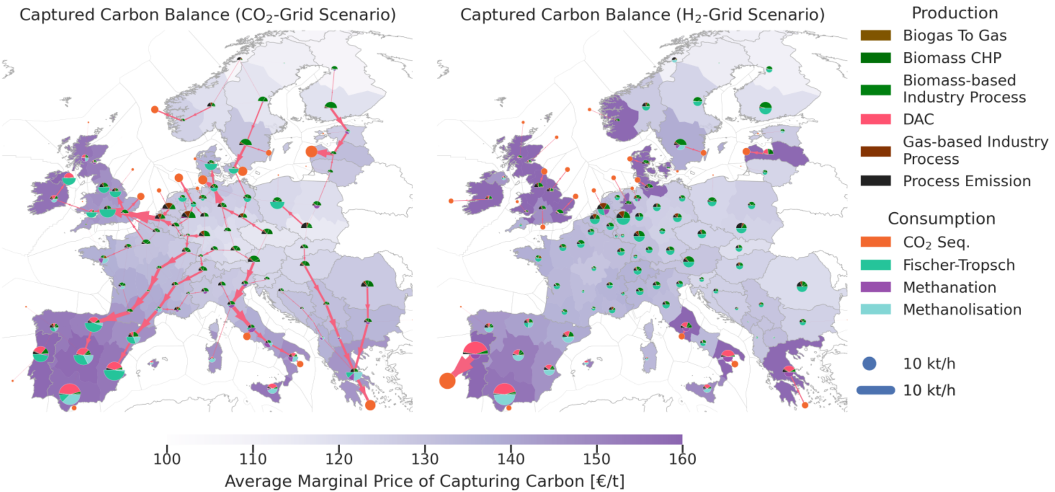
Source: Neumann et al, 2024

Energy infrastructure map for ‘all imports’



Source: Neumann et al, 2024

Don't forget the carbon network

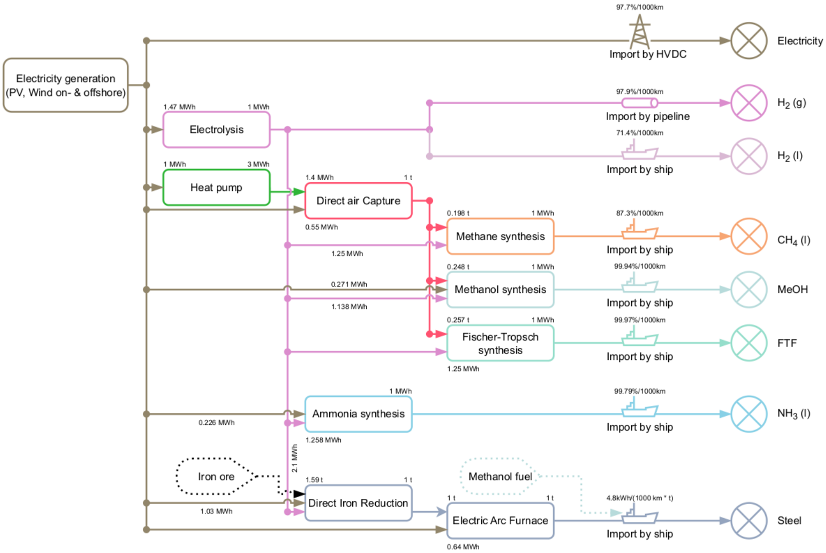


Source: **Hofmann et al, 2024**

Conclusions

- Results **highly sensitive** to inputs (WACC, electrolyser costs, waste heat, etc.)
- Cost-benefit for 1000-2000 TWh/a green imports to Europe, but **diminishing returns**
- Benefit seems clearest for import of hydrogen by pipeline from MENA, steel and methanol
- Some **advantages of domestic production** out-weigh the 'renewable pull' of abundant renewables outside Europe: flexible demand for local VRE integration, use of local biogenic CO_2 and waste heat integration to district heating
- The import strategy has **significant infrastructure impacts** that need to be thought-through - if infrastructure is delayed, may favour more imports
- Imports of $\sim$1000 TWh/a and some H2 pipelines from coast to inland appear **robust**
- Non-cost factors may drive infrastructure and import strategies: **geopolitical** considerations, **local jobs**, building **simple & easy-to-implement/regulate** systems, **reuse** of existing infrastructure, **resilience** of supply chains, diversification, and land usage

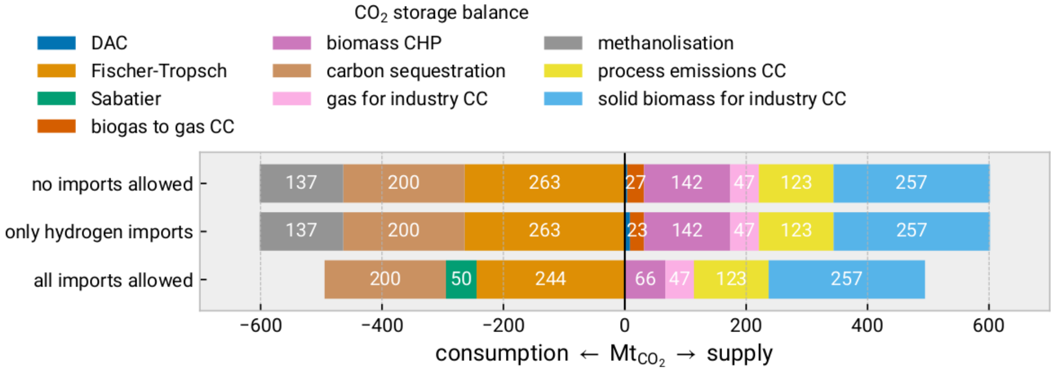
Energy imports



Source: Neumann et al, 2024

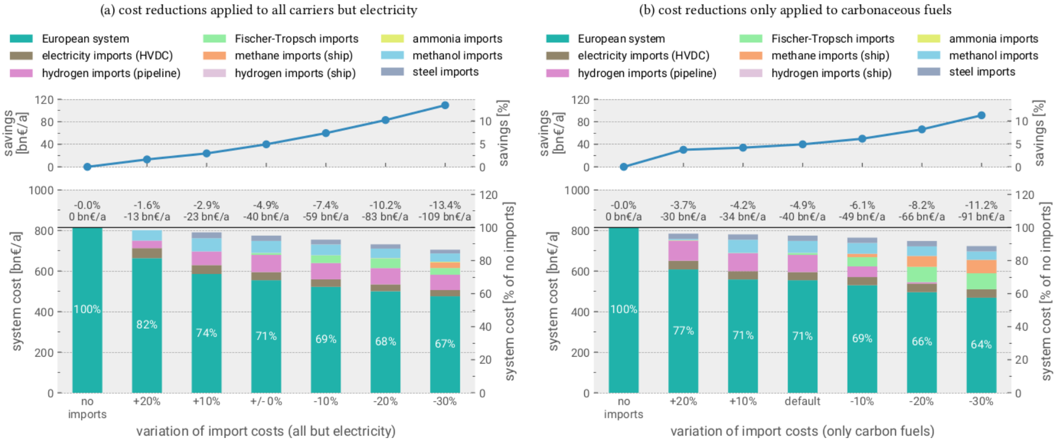
CO_2 balance

CCU and CCS take CO_2 from sustainable biomass and process emissions.



Source: Neumann et al, 2024

Effects of cost sensitivity



Source: **Neumann et al, 2024**

Case for Electrification plus Small Methanol Economy

Research hypotheses

- There is a **potential competition** between hydrogen and carbon transport; use CCS with fossil fuels, or CCU with synfuels to avoid most hydrogen needs (industry, power & heat)
- Most clear need of **carbonaceous fuels**: aviation, shipping, industry feedstocks
- How to get **decentralised** waste & residue biomass to these demands? Upgraded biogas? Pyrolysis + transport? Small-scale methanol synthesis?
- Hydrogen **hype** largely driven by gas industry, but hard to transport, store, requires GW infrastructure (pipelines, caverns), long deployment times, regulation difficult
- Models **don't see** many of these frictions and non-linearities
- Potential of **methanol** to take care of all 'hard-to-decarbonise', scales down well to multi-MW, easy to store and transport; needed anyway for industry & dense fuels

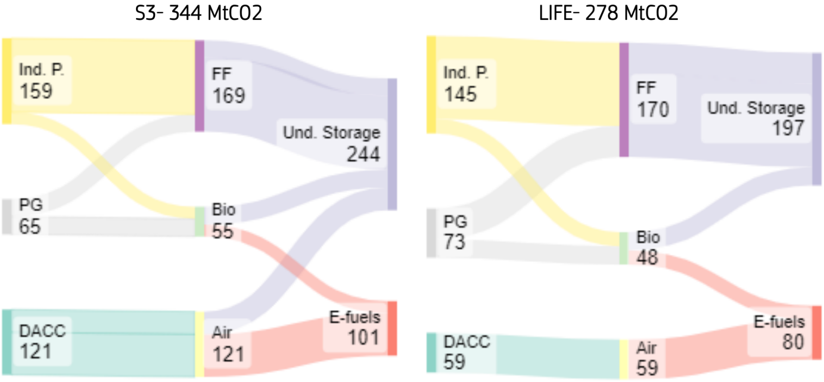
Which hydrogen demand sectors really need actual hydrogen?

For all hydrogen demand sectors there are **alternatives to transporting hydrogen**.

sector	alternatives if hydrogen not available
backup power & district heat	use derivative fuels (e-methane, e-methanol)
process heat	electrify/use derivative fuels
heavy duty trucks	use battery electric vehicles
iron direct reduction	industry relocates to cluster/abroad
ammonia	industry relocates to cluster/abroad
high value chemicals	transport derivative precursors instead
shipping	transport derivative fuels instead
aviation	transport derivative fuels instead

$\Rightarrow$ There is **no strict need** for transporting hydrogen, but it may be easier/cost-optimal.

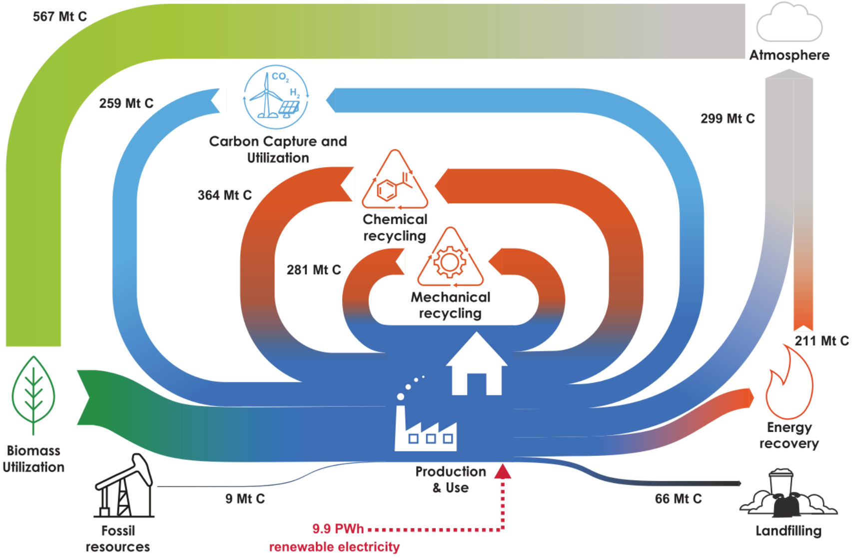
What we definitely need: carbon management



Note: "Ind. P." stands for Industrial processes and include fossil carbon from industrial processes as well as carbon of biogenic origin coming from the upgrade of biogas to biomethane. "FF" stands for "fossil fuels". "PG" stands for "power generation". "Bio" refers to CO2 produced by the combustion of biomass in power generation and produced during the upgrade of biogas into biomethane. "DACC" stands for "Direct Air Capture of CO2", for underground storage (DACCS) or use in efuels.

Source: [European Commission 2040 target impact assessment, 2024]

What we definitely need: carbon management

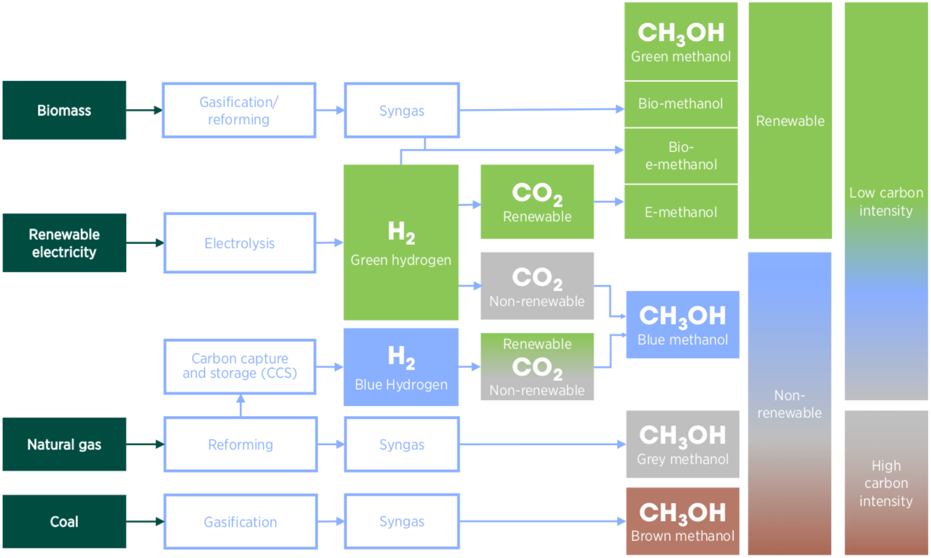


Source: Meys et al, 2021

Idea: ‘Electrification plus minimal methanol economy’

- **Electrify** as much as possible
- Use hydrogen for **sectors where really needed** (ammonia, maybe steel)
- Where it is difficult or slow to scale up hydrogen (e.g. delays in building pipeline network, technical problems with pipelines or turbines), consider **methanol instead**
- Methanol is more easily **storeable and transportable** than hydrogen
- Methanol **scales down** to small usage without lumpiness of big infrastructure
- Methanol can also be used for absorbing carbon from **biomass and wastes** (rather than biogas or inhomogeneous solid products), then using directly in industry or dense fuels
- **Cycle carbon** whereever possible (e.g. in power sector, industry and shipping)

Methanol routes



Source: IRENA, 2022

What about methane and bioenergy?

Technische Universität Berlin

Methane

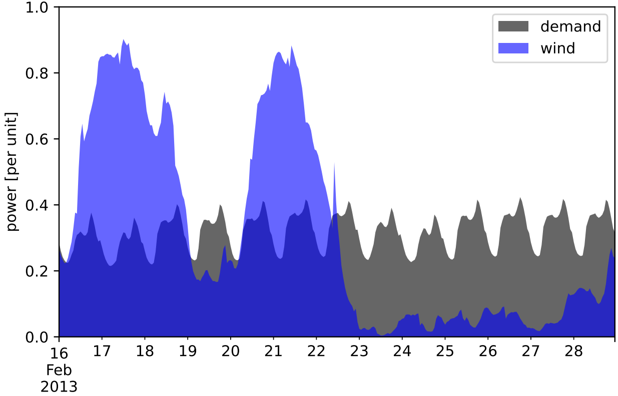
- There are very few sectors that need methane (beyond building heating until phase out is complete), whereas methanol has many uses; $CH_4 \Rightarrow$ lumpy pipelines
- Methane should be avoided in transport because of engine slippage, and in general because of leakage (possible to regulate, but in practice difficult)

Biomass

- Uses should be prioritised to: industrial feedstock, dense fuels for aviation and shipping, and carbon dioxide removal
- All of these needs can be met either with pure CO_2 (CDR) or methanol (MtO/A, MtK)
- Soak up all carbon close to source with biogas and e-H_2 in bio-e-methanol plants, or cellulosic ethanol, or gasification+synthesis
- Rare usage in CHP $\Rightarrow$ want low-capex plant using homogenous fuel (i.e. avoid solids)

Backup Power and Heat from Methanol with Carbon Cycling

With only wind and solar, need long-duration storage



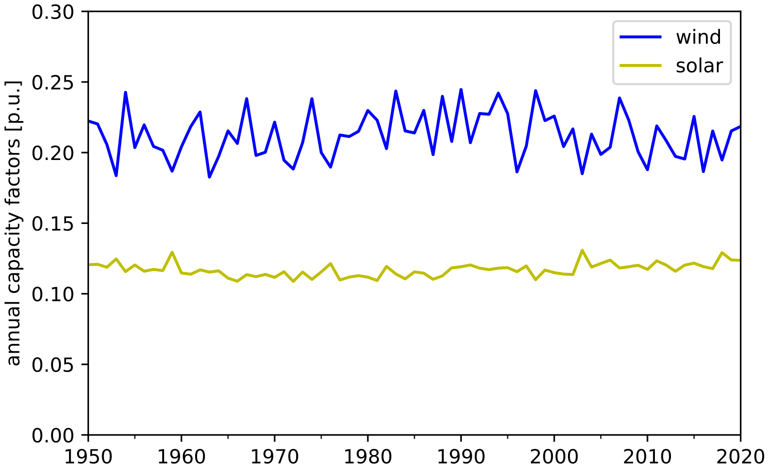
- Variability of wind and solar requires storage for **multiple days**
- Batteries cost 150-250 €/kWh, only suitable for a few hours
- Hydrogen pressure vessels cost 15-50 €/kWh, still too expensive
- **Underground salt caverns** for hydrogen cost 0.1-0.5 €/kWh, suitable for long-duration storage, **dominant concept in research**

Source: Irish wind and load data

Inter-annual variations of wind and solar

Particularly wind shows decadal cycles and strong **inter-annual variability**.

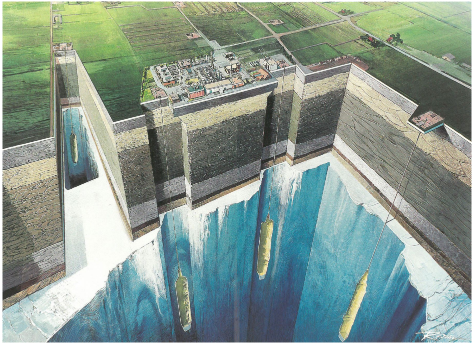
$\Rightarrow$ Need **ultra-long-duration energy storage** (ULDES), i.e. $>$ 100 hours.



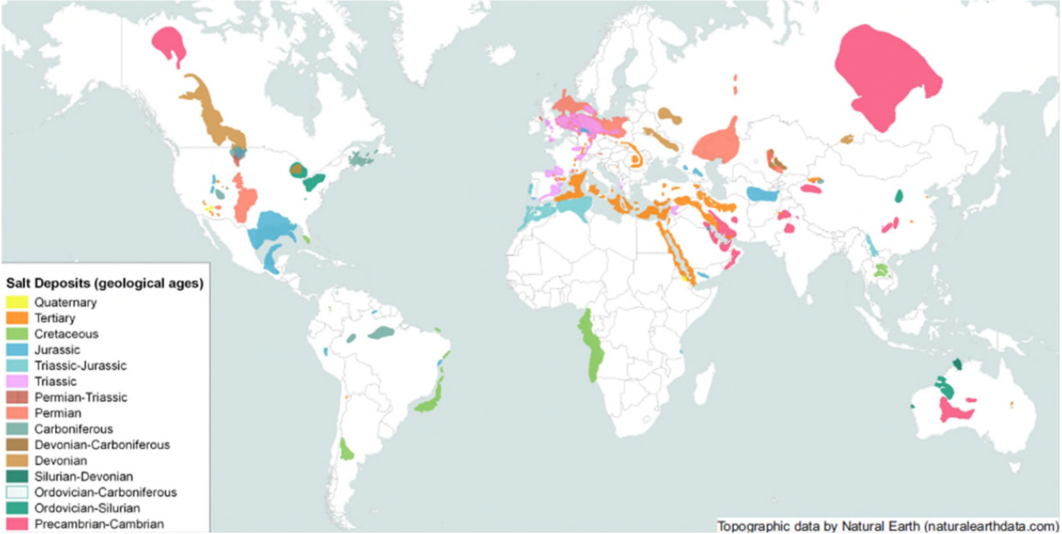
Source: Example of Germany

Establised idea: store hydrogen in salt caverns, transport by pipeline

Many countries plan to store hydrogen in **solution-mined salt caverns** and transport hydrogen in **pipelines** (can reuse fossil gas infrastructure for both).

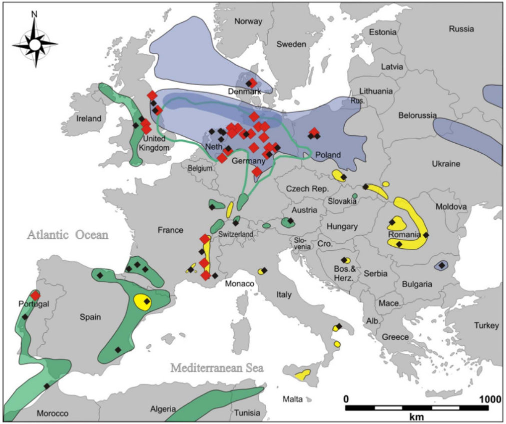


Problem: salt deposits for hydrogen caverns are highly localised



Source: [Solution Mining Research Institute]

Zoom on salt deposits in Europe and US



Tertiary salt deposit

Mesozoic salt deposit

Range of Mesozoic salt above Permian

Paleozoic salt deposit (Permian), Zechstein

Paleozoic salt deposit (Permian), Rotliegend below Zechstein

Salt cavern fields

Gas Storage

Storage of Crude Oil & LPG, Brine Production

Hydrogen versus its derivatives

Storing hydrogen in underground salt caverns has several potential issues:

- Salt deposits may be **lacking**
- Or may require **GW-scale** power transmission or hydrogen pipeline to access salt locations
- Hydrogen can **leak** with global warming impacts
- Caverns and transport infrastructure can be subject to **local pushback**

Hydrogen versus its derivatives

Storing hydrogen in underground salt caverns has several potential issues:

- Salt deposits may be **lacking**
- Or may require **GW-scale** power transmission or hydrogen pipeline to access salt locations
- Hydrogen can **leak** with global warming impacts
- Caverns and transport infrastructure can be subject to **local pushback**

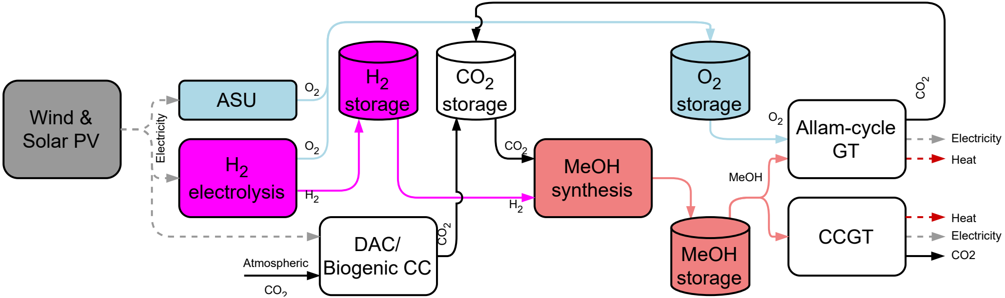
But looking to wider **hydrogen derivatives** we know we need

- **Ammonia** for fertiliser, perhaps shipping
- **Carbonaceous fuels** for aviation, shipping and chemical feedstocks

Why not use these for storage instead?

Technische Universität Berlin

Store energy as **methanol**; combust methanol in pure **oxygen** from electrolysis in **Allam cycle turbine**; capture pure **carbon dioxide**; then cycle for methanol synthesis with green hydrogen.



Source: Brown & Hampp 2023

Large methanol tanks can be built cheaply anywhere

- Methanol tanks cost just 0.01-0.05 €/kWh
- Single 200,000 m^3 tank can store **880 GWh**
- Can be built **anywhere**, take up little space
- CO_2 and O_2 stored cryogenically
- Can be dimensioned to provide **resilience** against low wind years, volcanos and infrastructure outages

Source: Wikipedia

All components are demonstrated at scale

A 50 MW_{th} Allam cycle turbine **already operating for years** in Texas; 300 MW_{el} plants to be commissioned by 2026. George Olah Renewable Methanol plant in Iceland commissioned in 2011 produces 4000 tons per year. Megaton methanol plants run in China on gasified coal.

Source: [NET Power](), [Carbon Recycling International]()

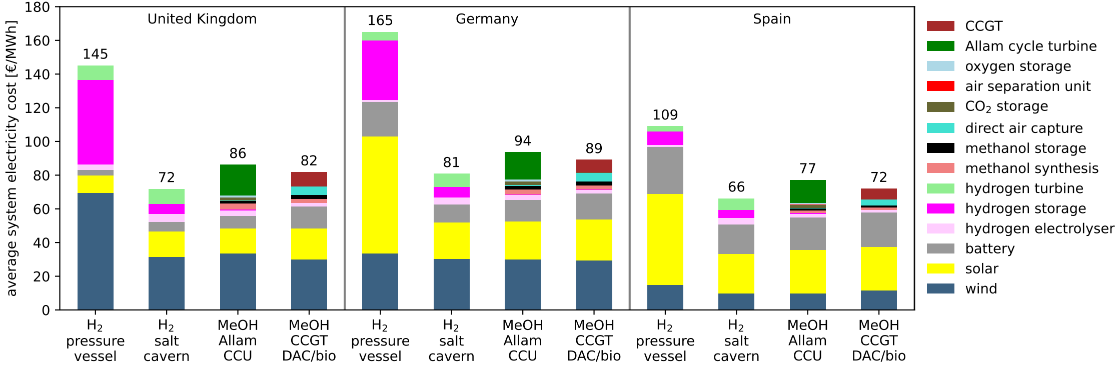
Study design

Optimise wind, solar, batteries plus one of following chemical carriers over **71 historical weather years** (1950-2020) for Germany, Spain and UK.

- **H_2 pressure vessel** - hydrogen storage in aboveground steel pressure vessels
- **H_2 salt cavern** - hydrogen storage in underground salt caverns (round-trip $\sim$ 38%)
- **MeOH Allam CCU** - methanol storage, all storage in aboveground steel tanks or pressure vessels, CO_2 captured from Allam cycle turbine (round-trip $\sim$ 35%)
- **MeOH CCGT DAC/bio** - methanol storage, all storage in aboveground steel tanks or pressure vessels, CCGT without CO_2 capture instead of Allam, all CO_2 for methanol synthesis from direct air capture (or biogenic sources)

Average electricity costs: UK, Germany, Spain

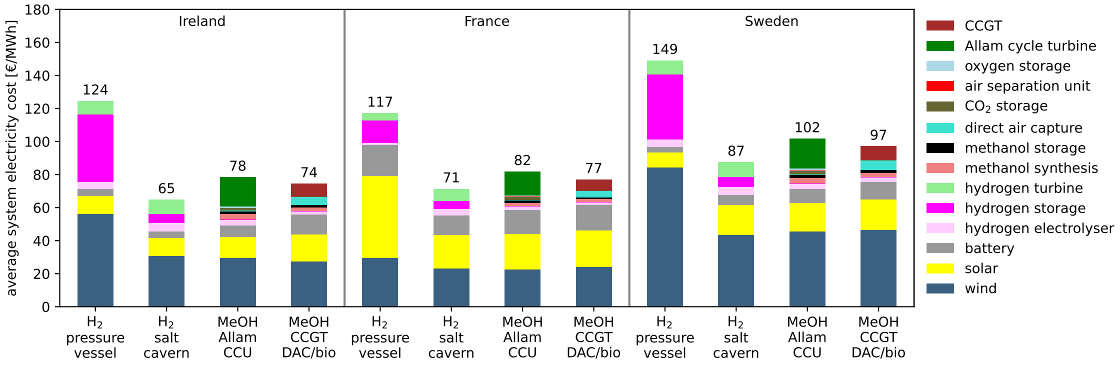
Methanol system **much cheaper** than H_2 pressure vessels where caverns not available; still 16-20% more expensive than salt caverns, but if Allam cycle costs reduce, only 6-7% more.



Source: Brown & Hampp 2023

Average electricity costs: Ireland, France, Sweden

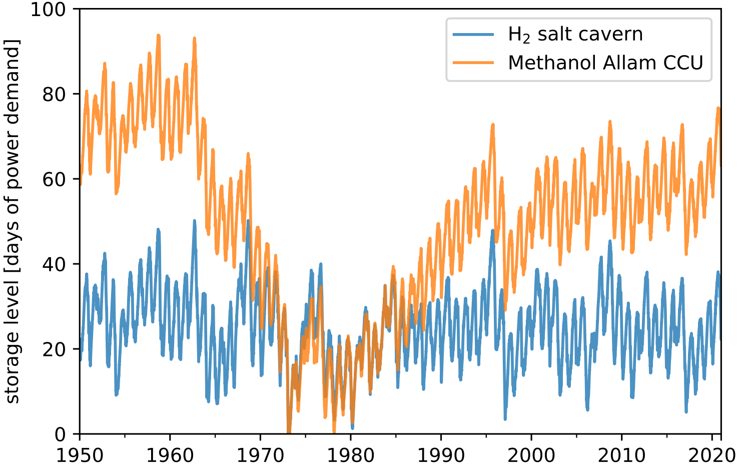
Similar results in Ireland, France and Sweden.



Source: **Brown & Hampp 2023**

Filling levels of storage in days of electricity demand

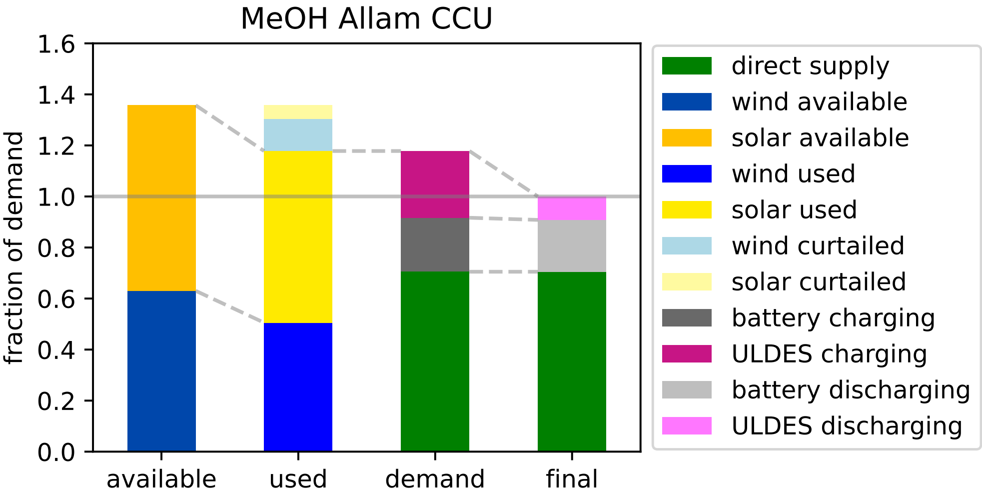
Methanol stored over many years for **multi-year reductions in wind output**. Storage large enough to cover **92 days** of electricity demand.



Source: Brown & Hampp 2023

Less than 10% of electricity provided by stored e-fuel

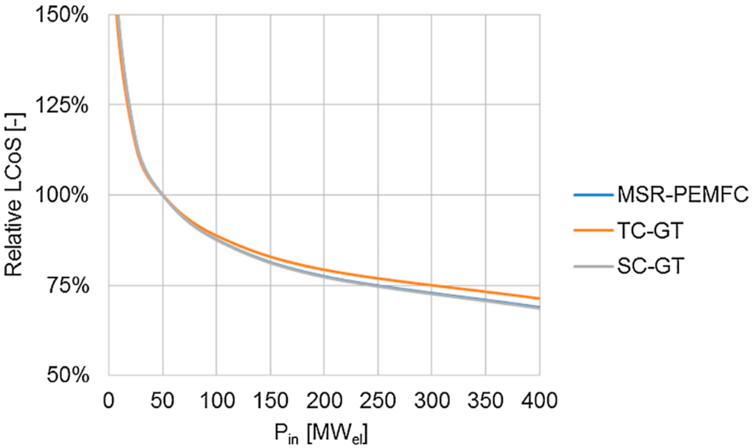
13% of available wind and solar is curtailed, a further 13% lost in storage conversion.



Source: Brown & Hampp 2023

Scaleability down to 200 MW

Economies of scale remain down to 200 MW (electrolyser power). ⇒ Interesting for **smaller autarkic regions**, such as islands or data centres. Also good for **fast, modular iteration**.



Source: [Baak et al, 2018]

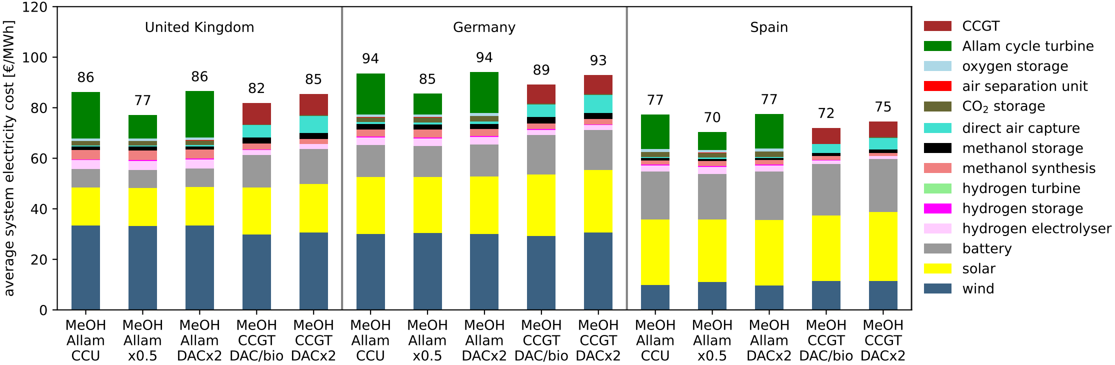
Pros and cons versus other chemical storage

- **Methane**: similar costs and efficiencies to methanol, can re-use existing infrastructure like methanol. Disadvantage of requiring pressurisation for storage and transport, leakage as greenhouse gas, needs GW economies of scale, could prolong fossil gas.
- **Ammonia**: has advantage of avoiding carbon cycle. But toxic, needs cryogenic storage, storage and transport is highly regulated, ammonia turbines have low TRL, nitrogen oxide emissions mean mitigation necessary.
- **Liquid hydrogen**: LH_2 requires constant cooling power, less attractive for ULDES.
- **Liquid organic hydrogen carrier**: LOHC similar to methanol storage, but more expensive and lower TRL. Waste heat from power generation can be used for dehydrogenation.

Sensitivity to cost assumptions

Technische Universität Berlin

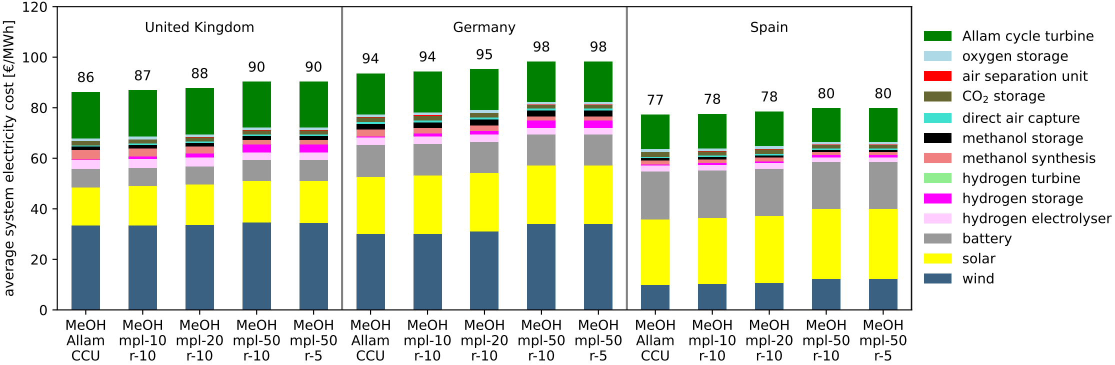
Effects of halving Allam cycle investment cost (from 1832 €/kW to 916 €/kW), doubling DAC investment cost (raises CO_2 cost in Germany from 202 €/tCO_2 to 316 €/tCO_2).



Source: Brown & Hampp 2023

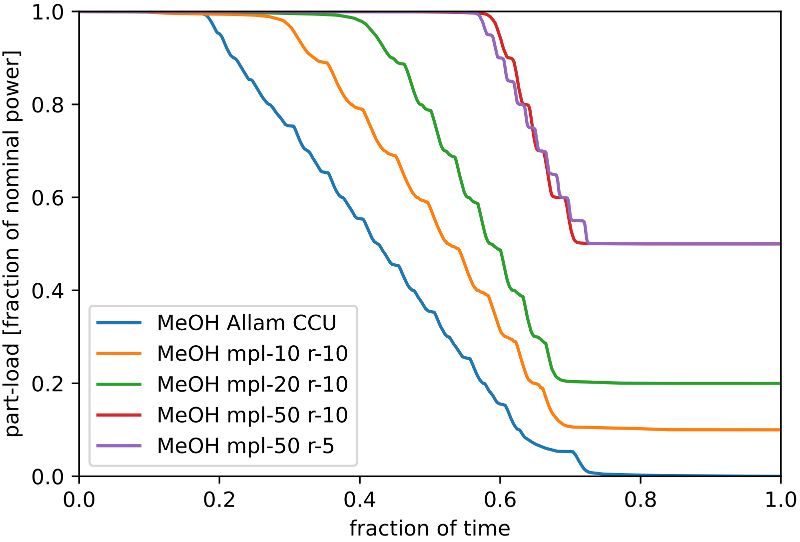
Sensitivity to flexibility assumptions

Fossil methanol synthesis typically runs with high capacity factors. Here we explore varying the minimum part load level (from 0% to 50%) and the hourly ramping limit (from 10% to 5%).



Source: **Brown & Hampp 2023**

Partload with different flexibility assumptions



Source: **Brown & Hampp 2023**

In short-term can take CO_2 from e.g. biogas, or convert all biogas to **e-bio-methanol**. But mid-term this CO_2 is needed by shipping and industry ⇒ **better to cycle if possible**.

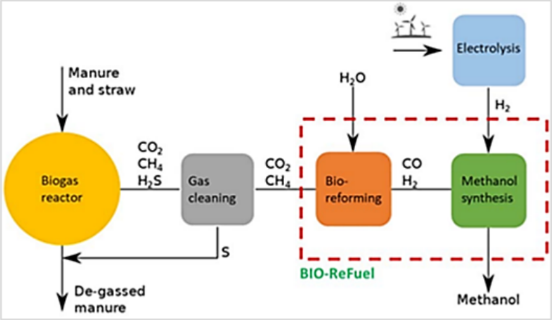


Figure 4: The process flow of bio-methanol production
Source: Lemvig Biogas

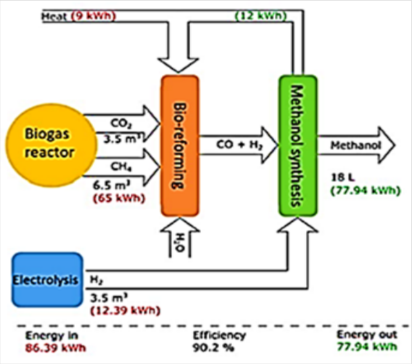


Figure 5: Energy balance
Source: Lemvig Biogas

Source: **IEA Bioenergy**

Conclusions

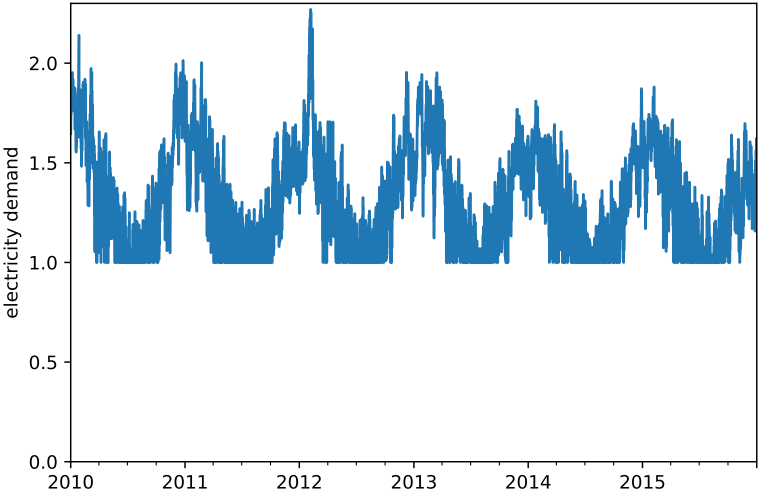
Conclusions

Technische Universität Berlin

- Methanol is a **scaleable and flexible** solution for hard-to-electrify sectors and carbon management (from biomass to industry/fuels)
- Systems built on wind and solar will need **long-duration** storage both for variability and **resilience** against rare extreme events
- Where salt deposits are not available, **methanol storage** provides an attractive alternative, whereby carbon is **captured and cycled back** to synthesis
- System costs are **much lower** than using hydrogen pressure vessels; costs are 6-20% higher than with hydrogen caverns, depending on cost assumptions
- By providing storage for many days, a methanol-based system is **resilient** against low-wind years, volcano eruptions and infrastructure interruptions
- **Further research** needed on synthesis flexibility, Allam cycle and system integration

Sensitivity to seasonal demand

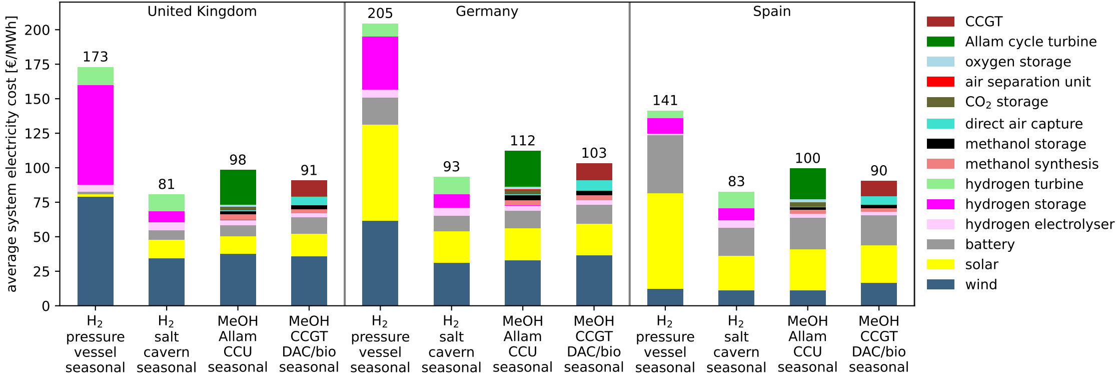
Suppose a third of demand comes from space heat pumps with **seasonal demand**.



Source: Example of Germany

Sensitivity to seasonal demand

Costs rise in all scenarios with 33% seasonal demand coming from heat pumps.



Technische Universität Berlin

Having both methanol and salt caverns; allowing CCS in Allam with fossil gas at 30 and 50 €/MWh_{th}.