Low-carbon hydrogen imports to Europe: Case studies and transformation pathways for ramping up green and blue hydrogen

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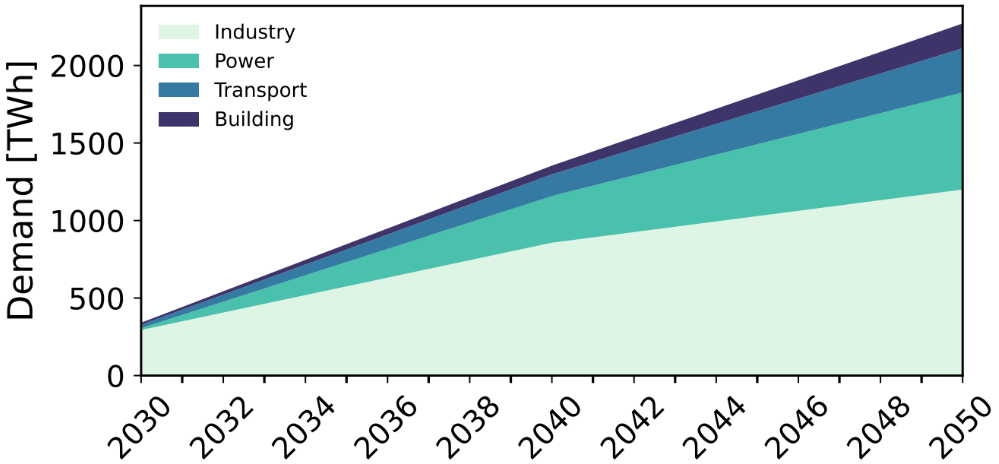
Motivation



Source: European Hydrogen Backbone

- Up to 2500 TWh of low-carbon hydrogen may be needed in Europe
- Blue hydrogen as a transitional pathway, but narrowing window
- Perspective of possible exporters of blue and green hydrogen, esp. fossil fuel exporting countries
- Case Study: Norwegian hydrogen exports

Expected Insights:

- **Export portfolio between NG and H2 for a country (while maximizing total profits)**
- **Timeline and switching points from NG to BH2 or GH2 and from BH2 to GH2, if at all**
- **What may be required to accelerate hydrogen ramp up?**

Norway as an energy exporter

Pipeline	Length [km]	Capacity [bcm]	Capacity [GW]	Max. energy flow [TWh]
Norpipe	440	16.0	18.2	159.5
Europipe I	620	16.7	19.0	166.3
Europipe II	658	26.0	29.6	259.1
Franpipe	840	20.0	22.8	199.4
Zeepipe	844	15.4	17.5	153.6

LNG Export Terminal	capacity [Mtpa]
Snohvit LNG	4.2
Risavika LNG	0.33

- Case Study: Norwegian hydrogen exports
- Excellent partnerships with Europe
- Existing infrastructure (fossil fuel industry) and financial strength
- Natural gas for blue hydrogen and experience in CO2 infrastructure
- RES potential for green hydrogen (offshore wind – 30 GW until 2040)
- Ambitious goals to continue exporting energy

Case Study Norway – Methodology

Profit maximization over 2023-2050 timeframe

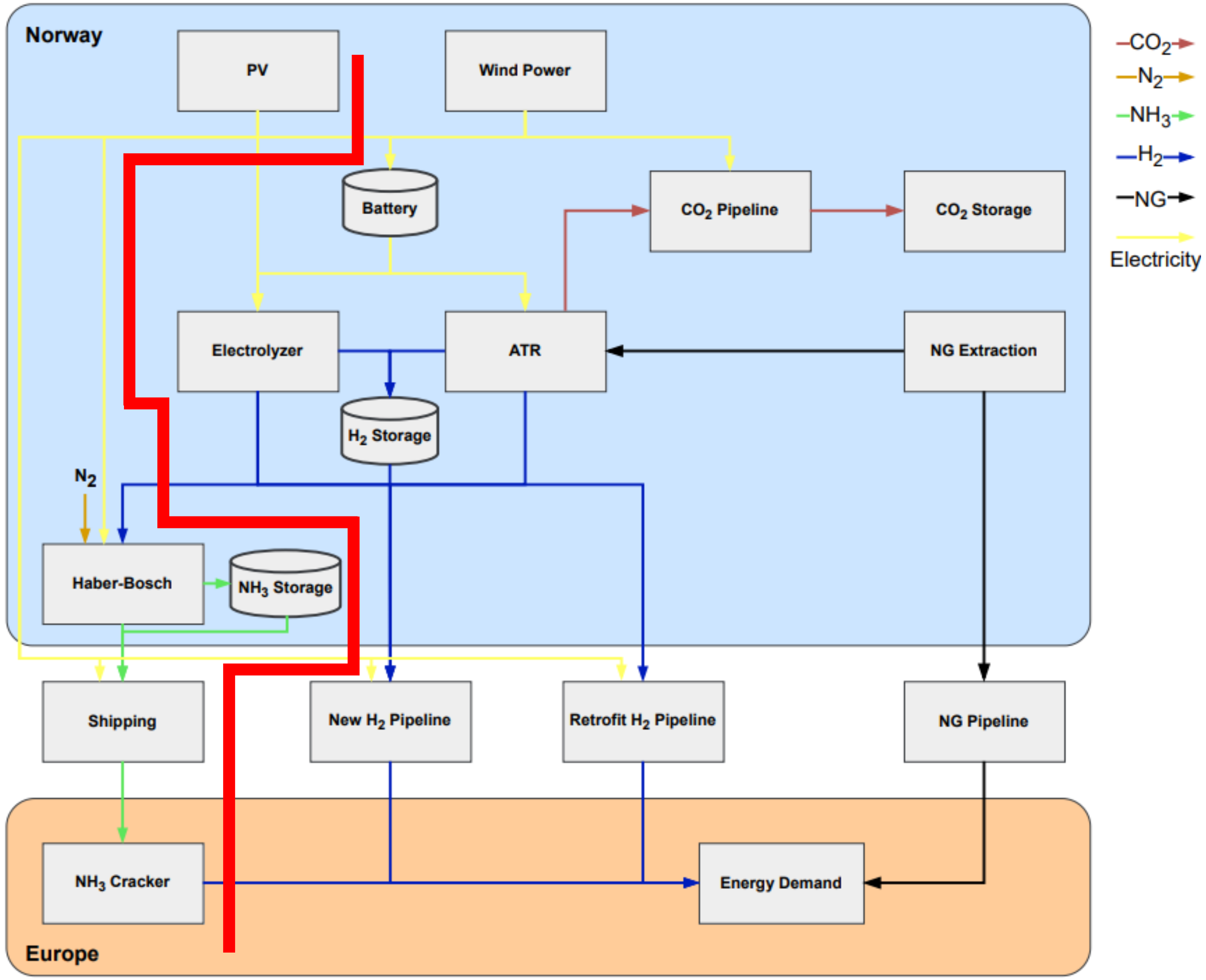
Objective function of MIP Model
Maximize all energy profits over the whole timeframe 2023 – 2050

Inputs	Outputs

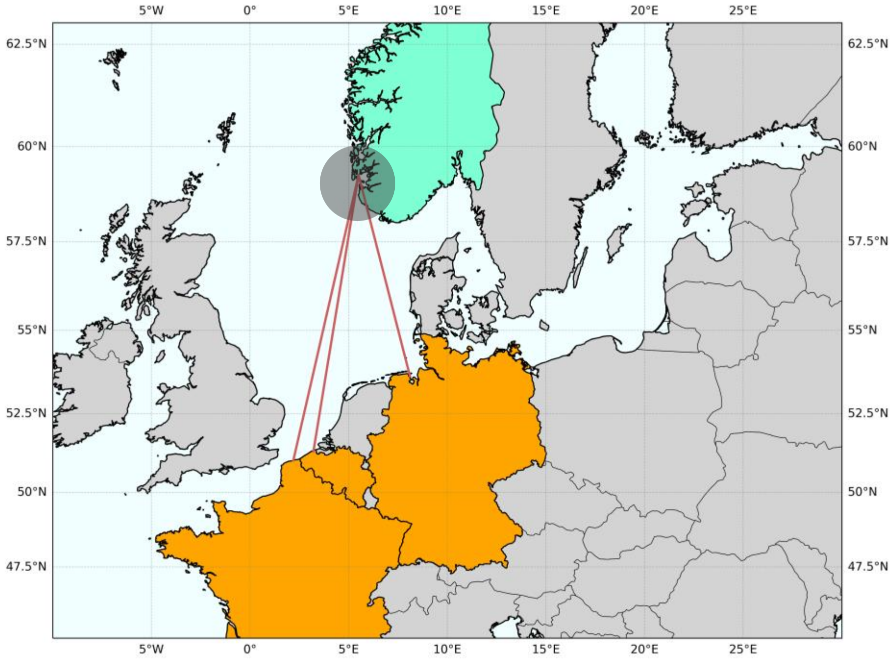
▪ RES hourly profiles
▪ Specific existing infrastructure in Norway
▪ Capital and operational costs
▪ Learning curves for RES/Electrolysis/CCS
▪ Price assumptions for CO_2/NG/BH_2 and GH_2
▪ Ramp-up limitations (RES expansion, infrastructural capacities, ...)
	▪ Total and annual profits over time frame
	▪ Total and annual supply costs and production costs over time frame
	▪ Retrofitting decisions
	Capacity expansions H_2/CO_2/NH_3:
	    ▪ Production and transport infrastructure
	    ▪ RES
	    ▪ Storages
	▪ CO_2 emitted and captured (from BH_2 production)

Case Study Norway – Methodology

Profit maximization over 2023-2050 timeframe



- Hydrogen production at feed-in points of existing NG pipelines
- CO2 transport 100 km average distance to sub-sea storages
- Retrofitting or purpose-built hydrogen pipelines possible
- Ends at receiving points in Europe
- Synergies of capacities possible (RES/pipelines)



Base assumptions

- Natural Gas price: 25 €/MWh (constant)
  - TYNDP2022: 15-25€
  - WEO2023: 20-25€

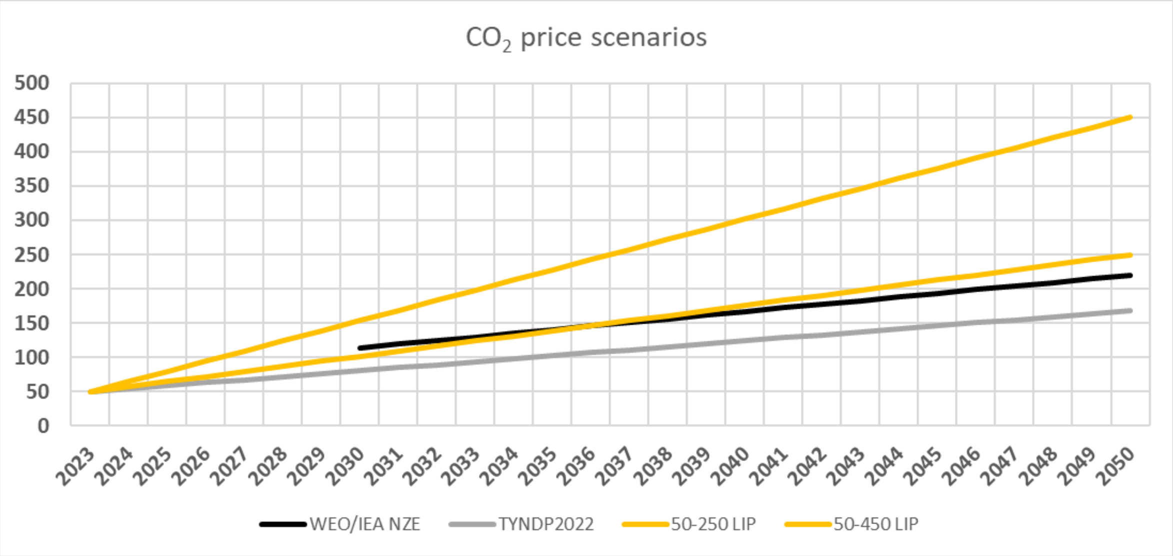
- CO_2 price scenarios (Today – 2050)
  - 50 – 168 €/t
  - 50 – 250 €/t (base)
  - 50 – 450 €/t

- NG and H_2 are perfect substitutes
  - H_2 price only driven by NG and CO_2 price
  - Maximum hydrogen price at which the decision for substitution from NG to GH_2 or BH_2 would be

- NG and H_2 Transport possible through 5 existing NG pipelines (optionally purpose-built H_2 pipelines or by NH_3 ship)

- Fixed premiums on GH_2 in increments of 15€/MWh (0,50 €/kg)
  - European Hydrogen Bank as inspiration

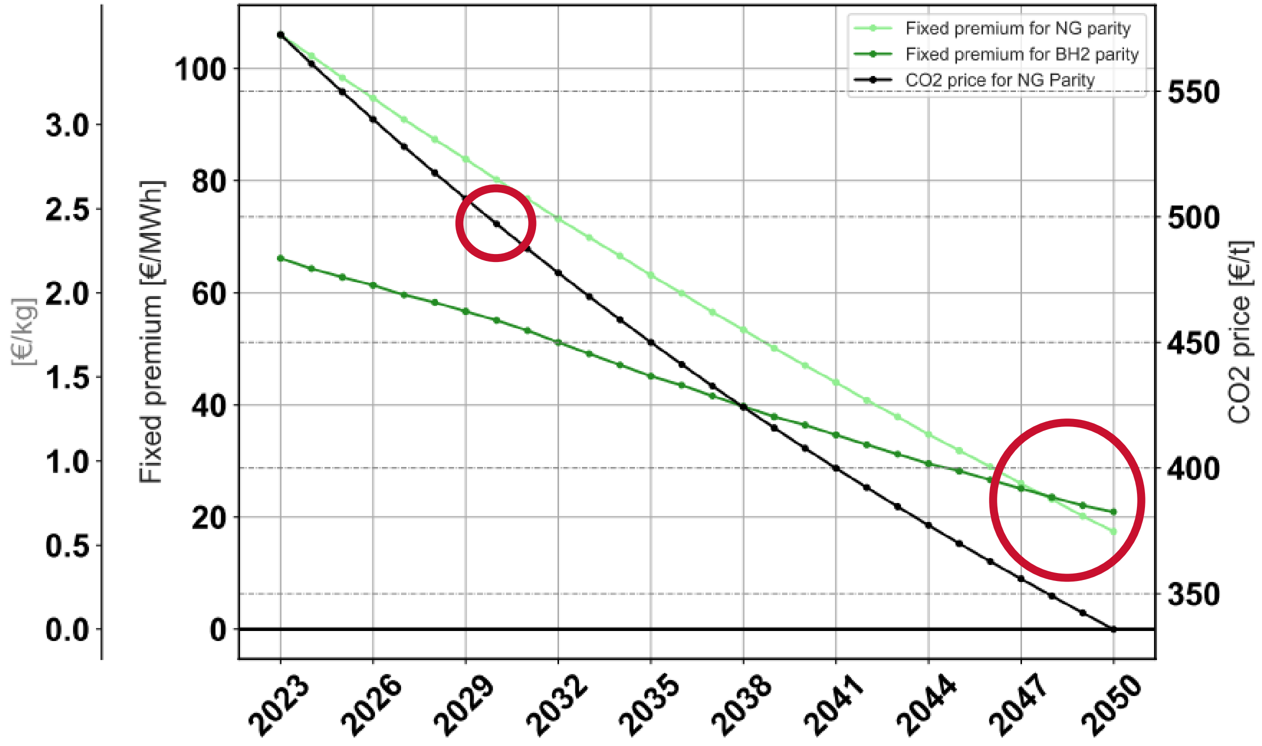
- 250 TWh annual energy demand (fulfilled by either NG or H_2) (10% of hydrogen demand in 2050, 100% of hydrogen demand in 2030 (EHB))

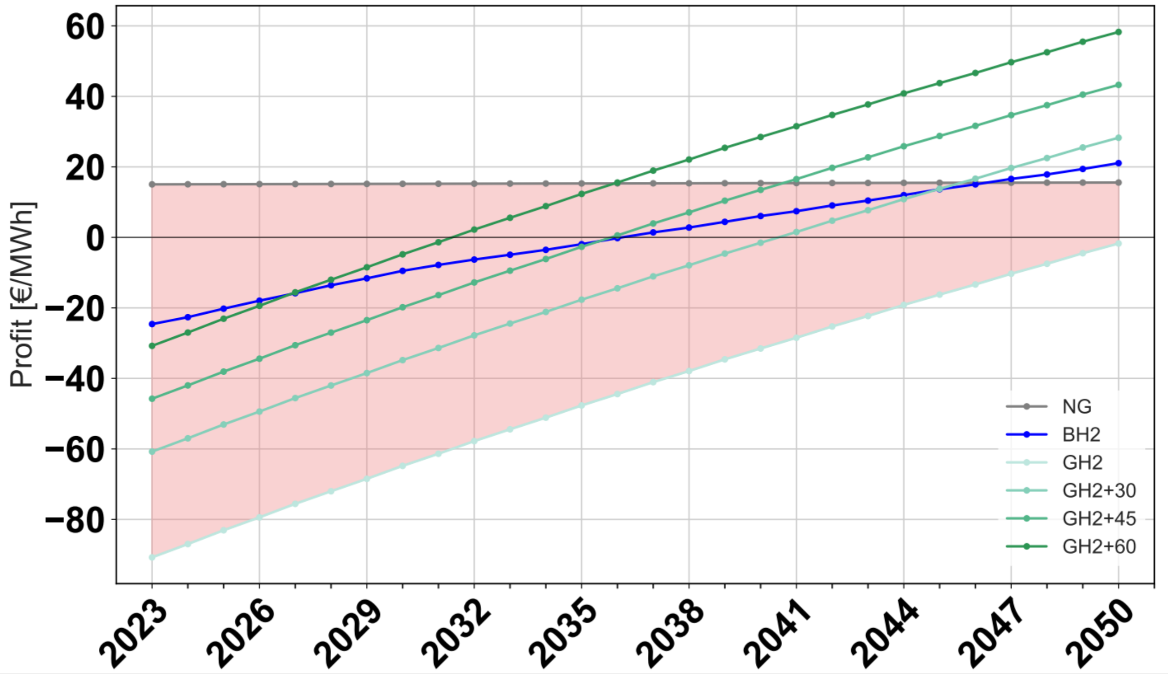


Preliminary results

Annual change for greenfield ramp-up/hydrogen production

- NG: 25 €/MWh
- CO_2: 50 – 250 €/t

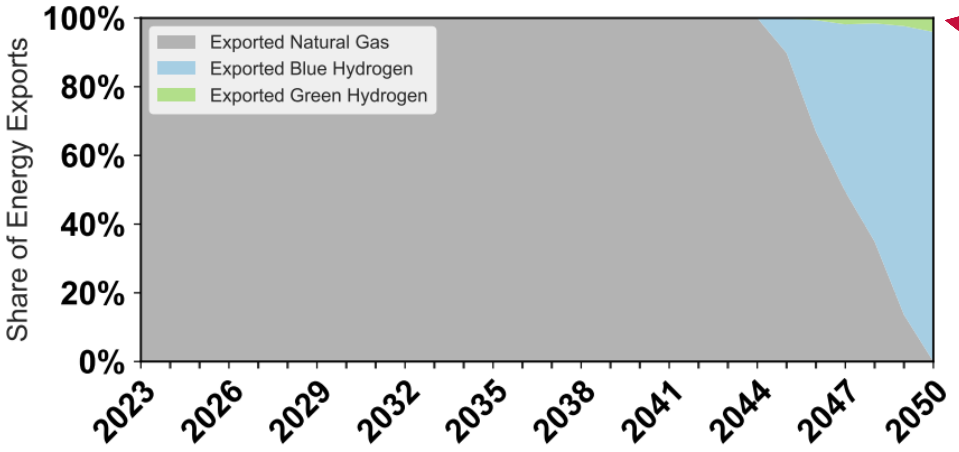




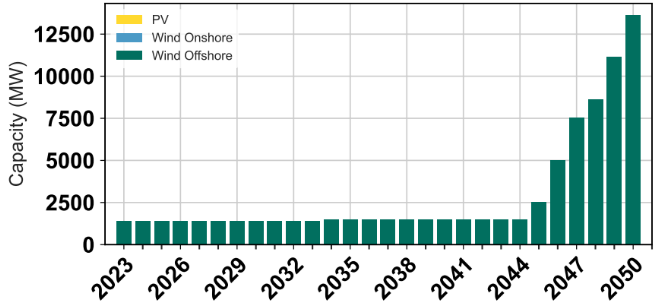
Preliminary results

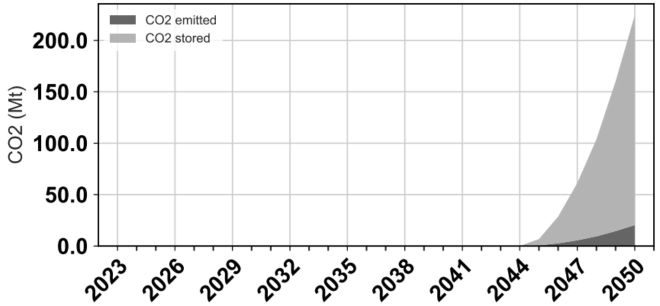
Base Case

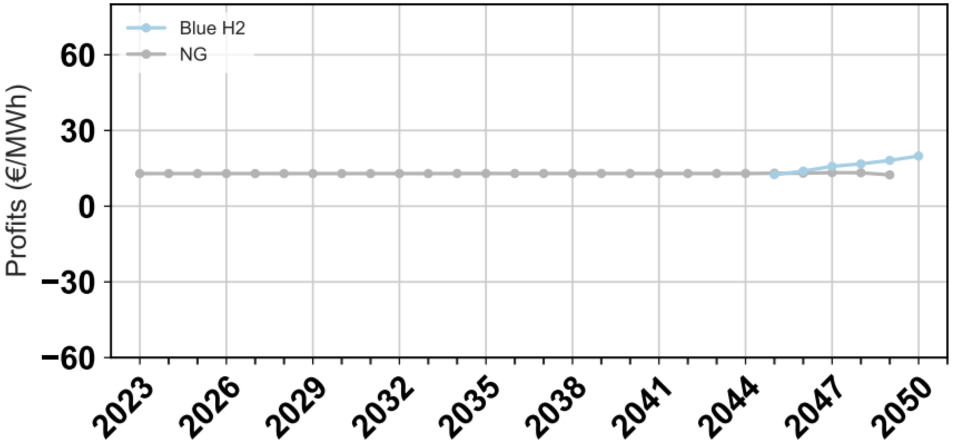
- NG: 25 €/MWh
- CO_2: 50 – 250 €/t
- Wind: 2500 MW/a



Mainly curtailment electrolysis



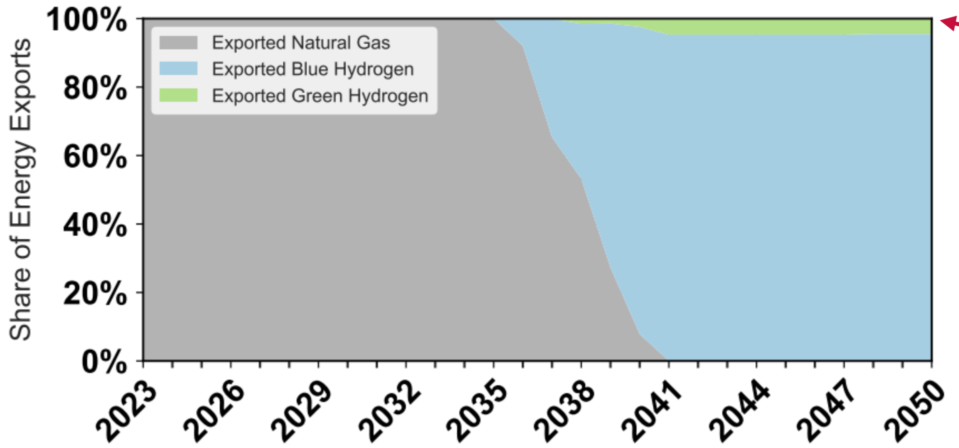




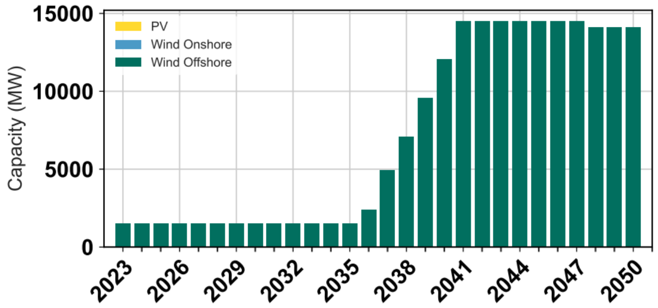
Preliminary results

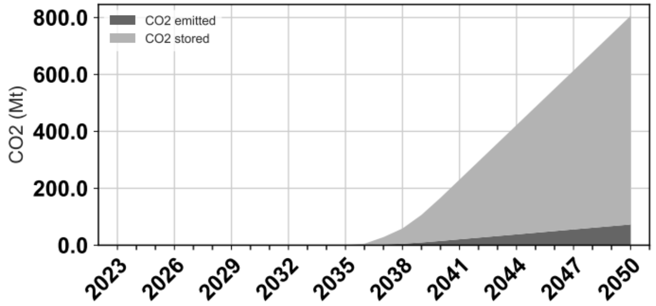
High CO_2 prices

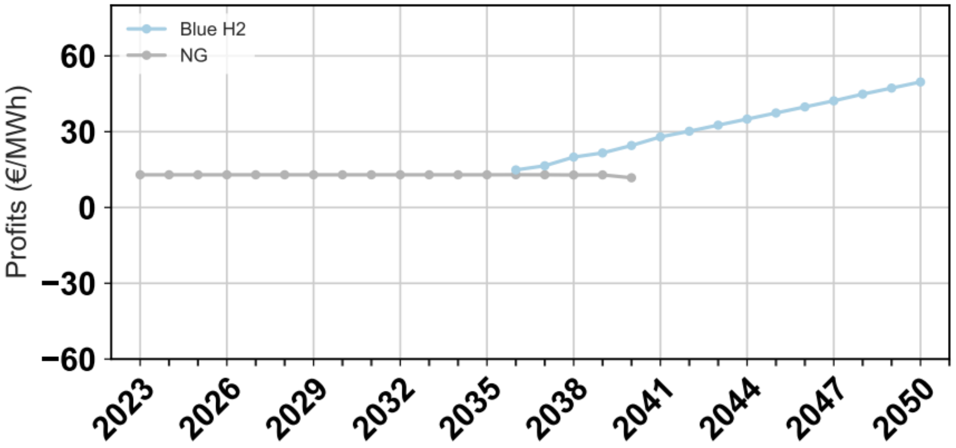
- NG: 25 €/MWh
- CO_2: 50 – 450 €/t
- Wind: 2500 MW/a



Mainly curtailment electrolysis



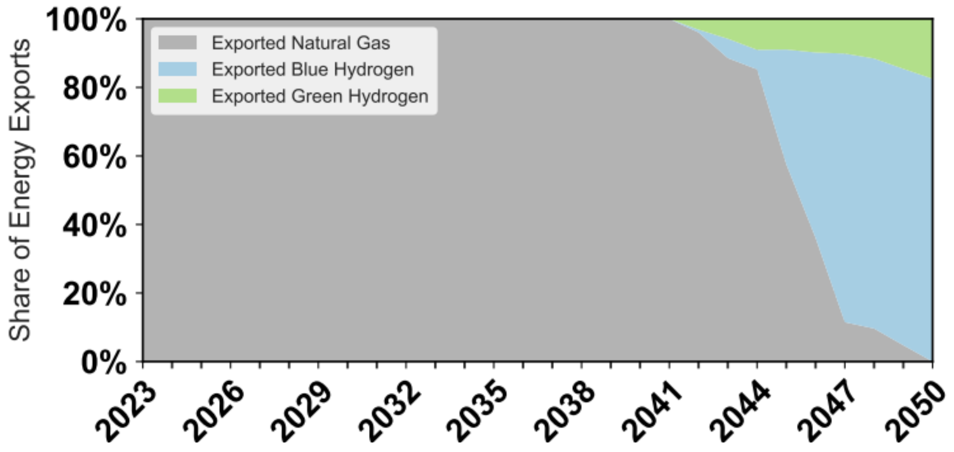


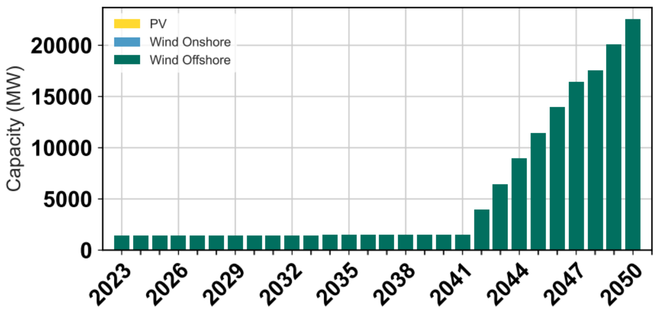


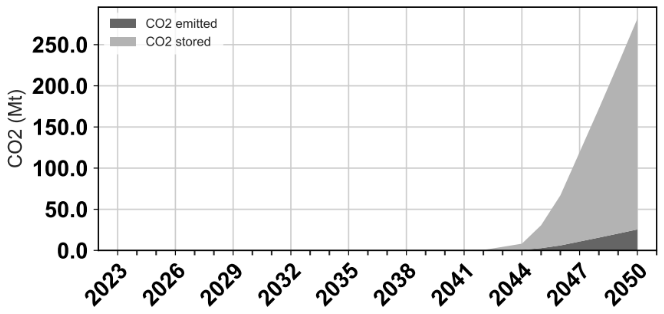
Preliminary results

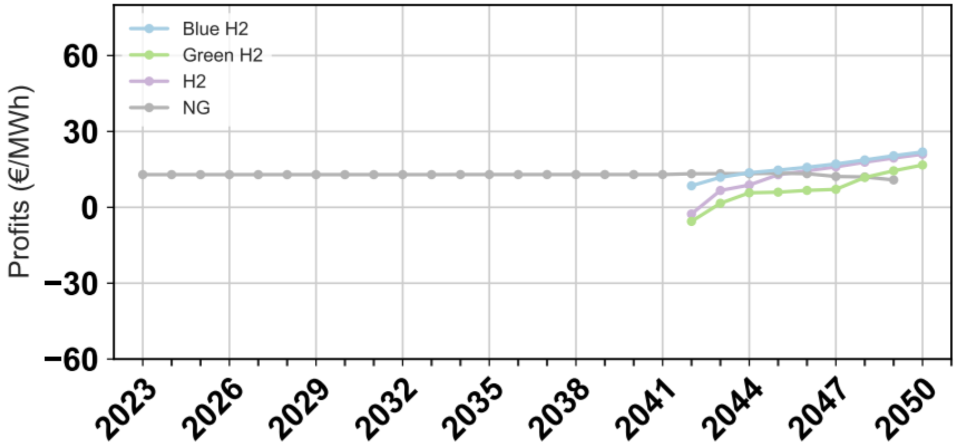
GH2 premium 30 €/MWh

- NG: 25 €/MWh
- CO_2: 50 – 250 €/t
- Wind: 2500 MW/a
- premium: 30 €/MWh





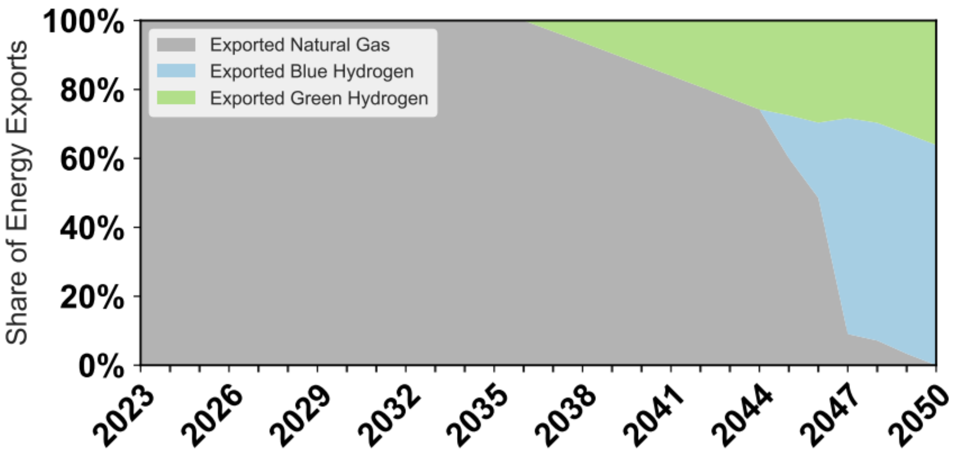


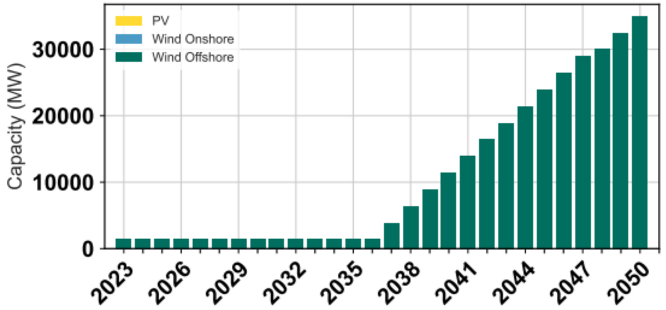


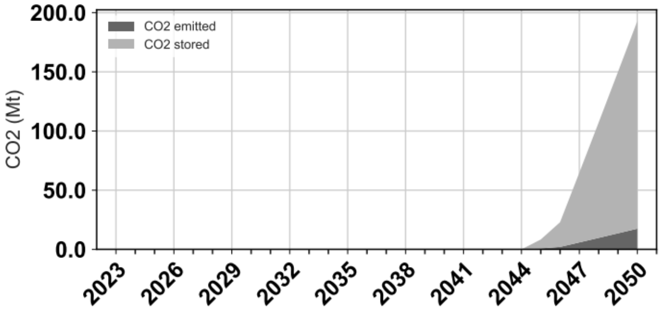
Preliminary results

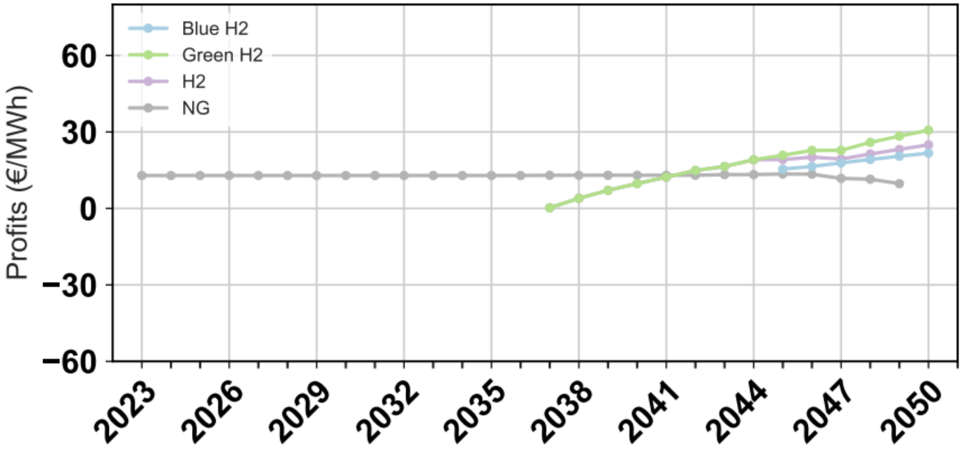
GH2 premium 45 €/MWh

- NG: 25 €/MWh
- CO_2: 50 – 250 €/t
- Wind: 2500 MW/a
- premium: 45 €/MWh





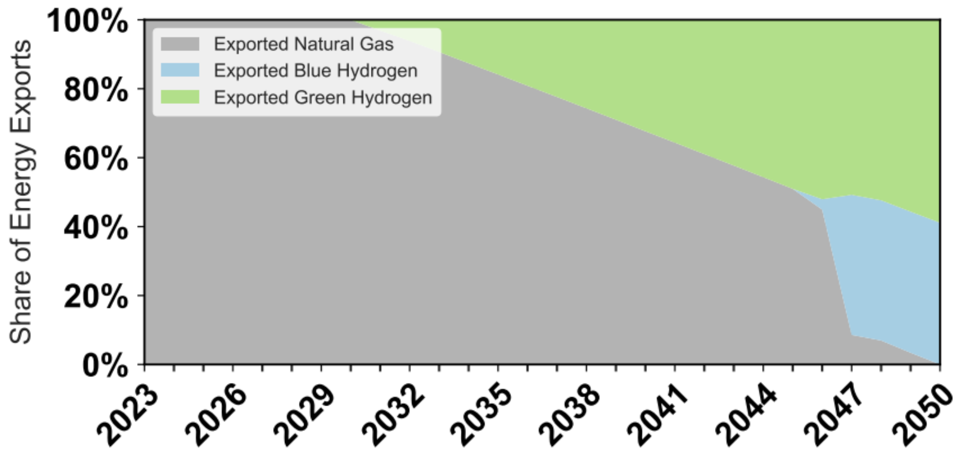


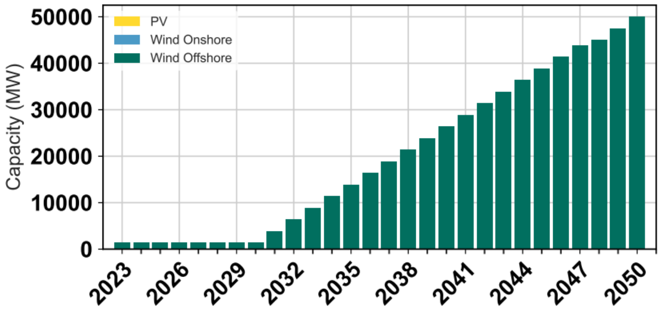


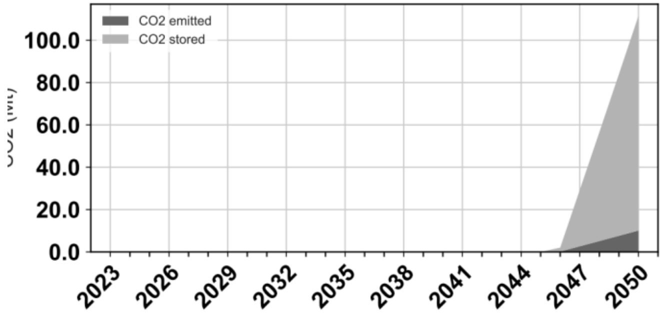
Preliminary results

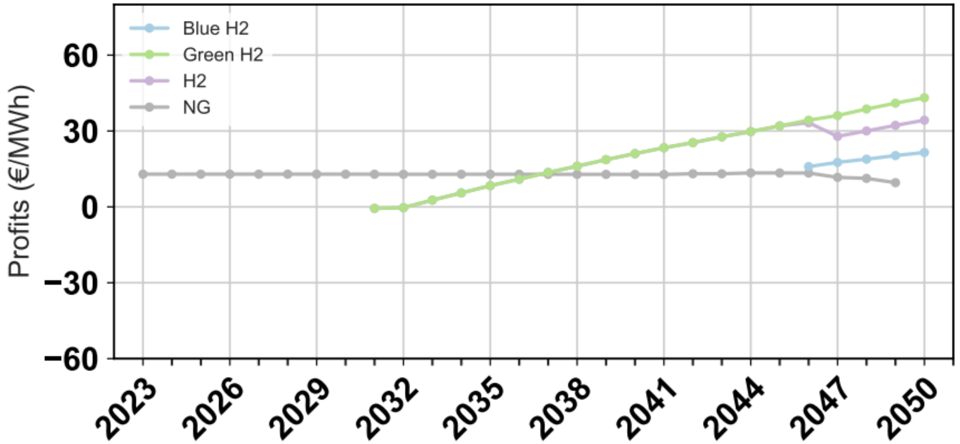
GH2 premium 60 €/MWh

- NG: 25 €/MWh
- CO_2: 50 – 250 €/t
- Wind: 2500 MW/a
- premium: 60 €/MWh









Implications and Outlook

Implications

- Often CO_2 prices and current cost reductions in RES and electrolysis not enough for timely and sufficient competitiveness of green hydrogen against natural gas and blue hydrogen
- ➢ Subsidies may cause a faster ramp-up for green hydrogen to also facilitate the learning curve of necessary technologies
- Slow or delayed ramp-up of RES also slows down green hydrogen deployment
- High CO_2 price may force earlier switch from NG to H_2 but not from BH_2 to GH_2 as it only minimally influences the cost of BH_2

Outlook

- Better hydrogen price and natural gas forecasting may improve the results
- Further restrictions? NG Reserves, raw materials, degressive premiums or CO_2 storage rates
- Different sensitivities, learning rates, supply chain modifications, and further countries

Thank you for your attention ☺

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