ROBUST SCENARIOS FOR GHG-NEUTRAL METHANOL IMPORTS TO EUROPE

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Abstract

Importing renewable energy to Europe can reduce system costs, ease infrastructure expansion, and limit domestic land use. Yet global exporting regions differ in renewable seasonality, geological suitability for hydrogen storage, and investment risks—factors that shape their competitiveness. Developing countries often face higher costs of capital for electricity generation and conversion technologies, which can distort competitiveness between global exporters and Europe. To assess these dynamics consistently, we integrate high-potential renewable regions outside Europe into a sector-coupled European energy system model that jointly optimizes renewable generation, hydrogen and methanol production, transport, and trade. This multi-regional framework captures cross-regional variations in renewable resources, financing conditions, and transport infrastructure, enabling a consistent evaluation of domestic versus imported production pathways across the full value chain. We find that high country- and sector-specific investment risks for capital-intensive electrolysis and carbon-capture technologies can outweigh strong renewable potentials, raising system costs and shifting cost-optimal mitigation efforts toward lower-risk regions.

Introduction

Meeting the Paris targets requires industrialized regions to reach net-zero GHG emissions by 2050. The EU's carbon-management strategy and Green Deal Industrial Plan therefore promote both large-scale carbon-dioxide removal and the substitution of fossil feedstocks [1], directing attention to GHG-neutral methanol for maritime, aviation and petrochemical use. Domestic renewables cannot satisfy future EU methanol demand: even optimistic assessments show sustainable biomass covering only a minor share [2]. Imports from regions with superior solar, wind or biomass resources are thus pivotal. The resulting geographic cost gradient—the "Renewables Pull Effect" [3]—creates incentives to relocate energy-intensive production steps abroad; such relocation could yield notable cost savings [4]. Technology choices—biomass conversion, CO_2-capture routes or recycling—remain site-dependent [5]. Scenario projections hinge on uncertain hydrogen prices, CO_2-source mixes and CCS costs [6]. This raises the research questions of this work:

- Which factors drive amounts and routes of imports?
- How does seasonality of energy imports impact energy import costs and infrastructure?
- How do differentiated cost of capital change capacity addition and cost allocation patterns?

We address these questions with a spatial linear cost-optimization model covering EU-27+3 plus northern Morocco as an explicit export region. The model couples hourly energy balances with regional biomass limits, multiple trade links, and then evaluate cost-optimal solutions according to national capacity additions and cost-allocation patterns. The resulting resilient import scenarios to 2050 inform policy on infrastructure priorities and trade strategy.

Methods and Data

We employ the hourly-resolved, country-level Enertile optimization model to co-simulate electricity, heat, hydrogen, methanol and CO_2 infrastructure for EU-27+3 plus global exporting countries. Inputs include technology cost curves, renewable and biomass potentials, and sectoral demand projections consistent with EU net-zero targets.

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The Energy System Model Enertile

Enertile is a country-level European energy-system model with hourly resolution that co-optimizes expansion and dispatch of electricity, heat, hydrogen and synthetic methane. It balances demand by investing in generation, conversion, storage and transport assets. Temporal flexibility—batteries, pumped-hydro, heat stores, hydrogen caverns, vehicle batteries—is complemented by spatial flexibility from endogenous electricity and hydrogen grid expansion. Hydrogen arises from electrolysis and can be reconverted to power or heat; CO_2 from DAC or cement and lime plants enables methanol synthesis from hydrogen beside bio-based synthesis.

Preliminary Results

In the baseline scenario, methanol production remains concentrated in Western Europe, with additional clusters in Poland and Norway. Cost differentials explain this pattern: the methanol shadow price is lowest in Morocco (≈ 120 €/MWh), rises in Scandinavia, and exceeds 140 €/MWh in central-eastern Europe. The main driver is hydrogen economics. The model yields an H_2 shadow price difference of 14 €/MWh between Morocco and Germany, reflecting the south-western solar advantage. Accordingly, Morocco exports between 100 and 200 TWh of each hydrogen and methanol via Spain to Europe. Germany, by contrast, is supplied predominantly from the Nordic countries via north–south pipeline links. Methanol synthesis locates where cheap renewable electricity powers both electrolysis and direct-air capture; high CO_2-pipeline transport cost discourage long-distance carbon transport, so cross-border CO_2 flows remain small. New hydrogen corridors connect Morocco to Spain, while shorter links move Nordic hydrogen into Germany and feed methanol plants.

Moreover*,* we find that high country- and sector-specific investment risks for capital-intensive electrolysis and carbon-capture technologies can outweigh strong renewable potentials, raising system costs and shifting cost-optimal mitigation efforts toward lower-risk regions.

Further analysis will quantify each scenario's "effort for change" by comparing capacity additions and shifts in cost allocation per country against today's system. It might reveal patterns of change and identify the least-resistance pathway as well as relative burdens, i.e. indicate how far and how unrealistically each option departs from the current situation.

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