International Journal of Hydrogen Energy 225 (2026) 154457

Contents lists available at ScienceDirect

International Journal of Hydrogen Energy

journal homepage: www.elsevier.com/locate/he

The role of green hydrogen imports under demand and supply uncertainties in Europe

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ARTICLE INFO

Dataset link: https://github.com/frederikdn/EMPIRE_H2Imports

Keywords:
Green hydrogen
Decarbonisation
European energy system
International trade
Energy systems modelling
Stochastic optimisation

ABSTRACT

To achieve climate neutrality, Europe's hydrogen strategy combines domestic green hydrogen production with green hydrogen imports, but the optimal balance remains uncertain. This study applies the stochastic energy system model EMPIRE, coupled with sectoral demand projections, to quantify how variable renewable energy source (VRES) deployment trajectories and hydrogen demand pathways jointly shape Europe's import requirements. Results show that import requirements in 2050 could range from 7.5 to 55 Mton/yr, depending on scenario developments. The pace of VRES expansion is the dominant driver, and even moderate acceleration beyond historical trends reduces cumulative hydrogen imports by 22%–33%, while stronger acceleration can largely eliminate structural import dependence, especially under a direct electrification pathway. High hydrogen demand consistent with REPowerEU targets is difficult to supply cost-effectively in the near term without substantial imports and some fossil-based hydrogen production. Imports are found to benefit short-term capacity building and to diversify against weather-induced variability, but their marginal value declines as renewable expansion and direct electrification advance.

1. Introduction

Amidst a persistent energy trilemma of sustainability, security of supply, and affordability, the European Union (EU) faces the challenge of transforming its energy system. Policy frameworks such as the European Green Deal [1], European Climate Law [2], and Fit-for-55 package [3] commit to at least a 55% reduction in greenhouse-gas (GHG) emissions by 2030 and climate neutrality by 2050. Recent geopolitical shocks have reinforced these ambitions, as the sharp decline in imports of Russian gas following the invasion of Ukraine exposed Europe's fossil-fuel dependence and intensified the drive for secure and affordable low-carbon alternatives. In response, the REPowerEU plan [4] targets the elimination of Russian gas imports before 2030 and sets a 20 Mton/year green hydrogen goal, split evenly between domestic supply and imports [5]. Ensuring affordability remains critical, as high volatility in fossil fuel prices and the costs of transitioning to low-carbon energy sources directly impact households and industries across the EU.

Green hydrogen is seen as central to the transition away from fossil fuels. It provides options as renewable fuel and industrial feedstock for steelmaking, ammonia production, and chemicals [6], and enables the production of synthetic e-fuels for aviation and shipping, where batteries remain impractical [7]. By complementing electrification, hydrogen broadens the portfolio of decarbonisation options available to Europe.

Realising this potential, however, is uncertain. Electrolyser manufacturing and deployment remain limited, infrastructure for storage and transport of hydrogen is nascent, and international trade partnerships are still forming [8,9]. Probabilistic assessments suggest that, if electrolysis expands at historical wind- and solar-like rates, green hydrogen would supply less than 1% of Europe's final energy by 2030. Achieving

Abbreviations: AEC, Alkaline Electrolyser Cell; CCS, Carbon Capture and Sequestration; CCUS, Carbon Capture, Utilisation and Sequestration; CVaR, Conditional Value-at-Risk; DAC, Direct Air Capture; EU27, European Union 27 member states; GHG, Greenhouse Gas; LH_2, Liquefied Hydrogen; LNG, Liquefied Natural Gas; PEMEC, Proton Exchange Membrane Electrolyser Cells; RES, Renewable Energy Source; SMR, Steam Methane Reforming; UHS, Underground Hydrogen Storage; VRES, Variable Renewable Energy Source

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https://doi.org/10.1016/j.ijhydene.2026.154457
Received 11 December 2025; Received in revised form 5 March 2026; Accepted 8 March 2026
Available online 13 March 2026

Table 1
Key modelling features in recent studies of international hydrogen imports to Europe.

Study	Model	Temporal scope	Geographical scope	Hourly resolution	VRES capacity factors	VRES deployment	Multi H_2 demand scenarios
Pinto et al. [16] (2024)	JRC-EU-TIMES	2030–2050 (10-yr steps)	Europe & North Africa	No	Deterministic	Endogenous	No
Guillot and Assoumou [17] (2025)	eTIMES-EUNA	2016–2050 (5-yr steps)	Maghreb & Europe	No	Deterministic	Endogenous	No
Ayed et al. [18] (2025)	TIMES-MAGe	2018–2050 (5-yr steps)	Maghreb	No	Deterministic	Endogenous	No
Schmitz et al. [19] (2024)	REMod /Enertile /SCOPE-SD	2020–2045 (5-yr steps)	Germany	Yes	Deterministic	Endogenous	No
Kigle et al. [20] (2025)	ISAaR	2030–2050 (10-yr steps)	Europe	Yes	Deterministic	Exogenous scenarios	No
van Greevenbroek et al. [21] (2025)	PyPSA-Eur	2025–2050 (5-yr steps)	Europe	No	Deterministic	Endogenous	Yes
Kountouris et al. [22] (2024)	Balmorel	2030–2050 (5-yr steps)	Europe	No	Deterministic	Endogenous	Partial
Neumann et al. [23] (2025)	PyPSA-Eur & TRACE	2050 (overnight)	Europe	No	Deterministic	Endogenous	No
Seck et al. [24] (2022)	MIRET-EU, Integrate Europe & HyPE	2016–2050 (10-yr steps)	Europe & International	No	Deterministic	Endogenous	Yes
Wetzel et al. [25] (2023)	REMix	2050 (snapshot)	Europe	No	Deterministic	Endogenous	No
Present study	**EMPIRE, TransportPLAN & IndustryPLAN**	**2025–2055 (5-yr steps)**	**Europe**	**Yes**	**Stochastic**	**Scenario-bounded (endogenous)**	**Yes**

the EU targets requires an emergency-deployment trajectory that exceeds conventional diffusion patterns and requires tight coordination across actors, supply chains and policy domains [10].

If the EU implements the necessary emergency-like measures to rapidly increase manufacturing capacity and diffusion, its green hydrogen ambition will ultimately depend on the pace of deploying variable renewable energy sources (VRES), as green hydrogen production relies on abundant and cheap electricity. Yet, wind and solar build-out face persistent permitting and social constraints [11]. The 2023 Wind Power Action Plan aims to enhance permitting, access to finance, and auction and trade practices [12], but persisting barriers to VRES deployment also limit hydrogen growth. Thus, Europe's pathway to climate neutrality depends not only on technology and cost but equally on political commitment [13], societal acceptance [14], and questions of energy sovereignty [15].

Developments in hydrogen demand are politically contingent. Historically, energy projections have primarily been linked to GDP and population assumptions. However, given current challenges, climate and sectoral policies necessitate structural changes that influence trajectories [21,26]. Direct electrification via electric vehicles and heat pumps can replace fossil technologies in many cases, while indirect electrification through hydrogen and e-fuels extends the decarbonisation portfolio to hard-to-electrify applications [27]. The relative emphasis on each of these routes will influence the eventual scale of hydrogen utilisation.

These interdependencies create cascading system effects. Higher demand for green hydrogen necessitates a proportionally greater capacity for renewable energy sources (RES), which amplifies deployment challenges [9,28]. Conversely, if domestic VRES expansion lags, green hydrogen imports become essential, introducing new trade dependencies and geopolitical considerations [23]. Hence, demand uncertainty is not merely a question of volumes — it directly links VRES expansion, hydrogen supply, and Europe's role in global energy markets.

Three uncertainties will therefore contribute to shaping Europe's hydrogen economy: (i) the pace, scope and scale of hydrogen adoption across industry and transport; (ii) the feasibility of VRES expansion amid technical, social, and supply-chain limits; and (iii) the cost, availability, and reliability of green hydrogen imports if domestic supply falls short.

Addressing these uncertainties requires modelling frameworks that integrate demand pathways, VRES deployment dynamics, and import strategies within a unified system modelling framework. Such approaches can support assessment of the robustness of Europe's hydrogen transition and identify the conditions under which imports become critical to achieving climate neutrality.

In the next section, recent modelling studies on hydrogen imports are reviewed, highlighting their treatment of demand uncertainty, VRES expansion, and international trade.

1.1. Literature review

Recent European studies have analysed hydrogen imports from multiple perspectives (Table 1). Scenario analyses with TIMES models of EU–North Africa trade [16–18] indicate that imports can lower European system costs, while shifting electricity, water, and infrastructure pressures to exporting regions. At the national level, a model study for Germany [19] finds that higher import prices incentivise domestic generation and electrolyser expansion.

Europe-wide assessments broaden these insights. The ISAaR study [20] shows that import and VRES deployment are linked, as examined through exogenous VRES scenarios. Robustness-oriented modelling with PyPSA-Eur [21] highlights that near-optimal domestic production mitigates uncertainty in imports, CCS, and biomass. Infrastructure analyses with Balmorel [22] focus on hydrogen-network design, showing that sovereignty trade-offs influence corridor choice and cost. TRACE–PyPSA-Eur modelling [23] demonstrates that importing hydrogen or energy-intensive materials such as steel and ammonia can reduce Europe's own network size by up to 70%.

Integrated system frameworks add further dimensions. The MIRET-EU study [24] links three models to propose a balanced mix of VRES and low-carbon hydrogen, while REMix-based analysis [25] finds that a fully domestic strategy is feasible but around 3% more costly than cooperative import pathways.

Across this literature, several gaps persist. Most studies assume a single hydrogen-demand pathway and rarely explore demand uncertainty. Natural gas dynamics are often oversimplified, lacking explicit Russian import phase-out ambitions that are closely linked to hydrogen uptake. Temporal resolution is frequently reduced through aggregation, missing hourly operational and load dynamics, and deterministic single-year weather modelling limits the robustness of investment decisions. VRES expansion is commonly cost-optimised or linearly constrained instead of being bounded by S-curve developments that reflect empirical build rates [29]. Together, these simplifications tend to yield point-optimal import estimates under idealised conditions, rather than robust ranges across plausible futures and variable weather.

1.2. Scope and contribution

The present study addresses three key research and knowledge gaps: (i) it applies logistic upper-bound growth scenarios for VRES deployment (historical, low, accelerated, and high variants) that reflect empirically observed S-curve build-out patterns in wind and solar; (ii) it employs an energy system model with stochastic multi-year weather data at hourly resolution to assess imports, adequacy, and electrolyser operations under variable conditions; and (iii) it links least-cost operation and capacity expansion with two demand models to examine alternative demand trajectories while enforcing a European CO_2 reduction path and a phase-out of Russian pipeline gas before 2030.

Combining these elements allows us to quantify the green hydrogen import requirements, accounting for the effects of changing weather, uncertainties in demand and VRES scaling, and policy contexts, providing an integrated view of how hydrogen trade contributes to Europe's pathway toward climate neutrality. This enables us to answer the following research question:

To what extent will Europe require green hydrogen imports toward 2050 given uncertainties in hydrogen uptake and VRES availability?

The remainder of this paper presents the modelling framework and demand projections (Section 2), the case study design (Section 3), the main results (Section 4), and discussion and directions for future research (Section 5), followed by the concluding remarks in Section 6. Key assumptions regarding technical and cost data are provided in Section 2 of the Supplementary Materials.

2. Methods and materials

This study quantifies the European green hydrogen import needs by coupling the EMPIRE energy system model (Section 2.1) with sectoral demand projections from IndustryPLAN and TransportPLAN 2.2. The EMPIRE model [30] is a long-term stochastic capacity-expansion model co-optimising electricity, gas, and hydrogen sectors to minimise discounted system costs under demand and emission constraints [31]. This study expands the EMPIRE model with explicit hydrogen import options and logistic bounds on VRES growth.

Exogenous demand trajectories from IndustryPLAN [32] and TransportPLAN [33,34] define high and low hydrogen demand scenarios. VRES expansion follows logistic functions calibrated to historical build rates 2.1.2; Russian pipeline gas ends after 2030 [35], while imports from North Africa (Maghreb region) and liquefied natural gas (LNG) sources will continue.

The model spans the EU27 plus Great Britain, Norway, Switzerland, and the Balkans, enabling endogenous optimisation of generation, storage, and hydrogen infrastructure across the interconnected region. The considered planning period is 2025–2055 with five-year steps.

2.1. EMPIRE

The European Model for Power System Investments with Renewable Energy (EMPIRE) [30] is a multi-horizon stochastic optimisation model linking long-term capacity expansion with short-term operations under uncertainty. The model minimises expected discounted system cost subject to demand, technical, and CO_2-emission constraints. Investment decisions are made for each five-year strategic (investment) period spanning 2025–2055. Each strategic period represents a single five-year interval, and investment choices taken for that interval remain binding across all stochastic scenarios. Within each strategic period, system operation is modelled at hourly resolution with 720 hourly timesteps per stochastic scenario per strategic period.

Short-term uncertainty in VRES availability and demand profiles is represented through 5 stochastic operational scenarios. Following the EMPIRE sampling procedure, each scenario is generated by random sampling from historical hourly data while preserving temporal autocorrelation (chronological sampling within each season) and spatial correlation (the same sampled hours are used across all nodes). Representative operation within each scenario consists of four seasonal weeks and two peak-day windows, which are scaled to represent a full operational year [31]. The five scenarios are therefore random historical realisations, sampling available data for the period 2015–2019. Therefore, the five scenarios are sampled on equal terms, and are weighted equally in the objective function, reflecting the absence of pre-determined information favouring one sampled realisation over another [31]. Five scenarios are used as a balance between representing inter-annual variability and maintaining computational tractability, noting that each additional scenario increases the operational problem size proportionally.

This formulation allows joint assessment of domestic supply, hydrogen imports, and emission targets, linking investment, operational flexibility, and VRES uncertainty across power, natural gas and hydrogen markets. Subsequent subsections detail the implementation of hydrogen import options and VRES upper bound scenarios within EMPIRE.

2.1.1. Modelling of hydrogen imports

This subsection outlines the linear programming (LP) formulation of international hydrogen imports within EMPIRE. A full model description is available in Backe et al. [30] and related work. All model nomenclature is presented in Section 1 of the Supplementary Materials. The techno-economic parameters used in modelling international hydrogen imports, along with other key data, are provided in Section 2 of the Supplementary Materials, with references to data sources.

Eq. (1) presents the EMPIRE objective function, focusing on novel implementations in EMPIRE related to international hydrogen imports, while all other system costs are compiled in the aggregate term C_i^{sys}. These other system costs comprise the investment costs of generators, storage, and transmission, and the operational costs of generators, including lost load, for the power and industry sectors in EMPIRE. Please refer to Backe et al. [36] for a full representation of this aggregate term in EMPIRE.

$$\min \sum_{i\in I}\Big[DF_i \times \Big(\underbrace{\sum_{(n,t)\in A} C^{\mathrm{inv}}_{n,t,i}\, x_{n,t,i}}_{H_2 \text{ import investment}} + \underbrace{SF \sum_{(n,t)\in A} C^{\mathrm{fix}}_{n,t,i}\, x_{n,t,i}}_{H_2 \text{ import fixed O\&M}}$$

$$+ \underbrace{SF \sum_{w\in W}\Big(P_w \sum_{s\in S}\Big(w_s \sum_{h\in H_s}\sum_{(n,t)\in A} C^{\mathrm{marg}}_{n,t,i}\, y_{n,t,h,i,w}\Big)\Big)}_{H_2 \text{ import short-run marginal cost}} + C_i^{\mathrm{sys}}\Big)\Big], \tag{1}$$

$\forall i \in I,\ (n,t) \in A,\ w \in W,\ s \in S,\ h \in H_s.$

The model minimises the expected present value of total system cost across strategic periods i and weather years w. The discount factor

DF_i applies to all cost components in period i. The scaling factor SF is applied only to operating-cost terms (fixed O&M and short-run marginal costs) to (i) scale costs from the representative hours to an annual estimate and (ii) convert annual operating costs to the present value of the five-year strategic (investment) period. Investment costs are one-off decisions in period i and are therefore not multiplied by SF.

Eq. (2) defines the installed capacity of hydrogen import terminals, accounting for asset lifetimes across discrete investment periods.

$$\underbrace{\sum_{j\in I:\ i-L_t+1\le j\le i} x_{n,t,j}}_{\text{Additional } H_2 \text{ capacity}} = \underbrace{\bar{x}_{n,t,i}}_{H_2 \text{ capacity}}, \quad \forall (n,t)\in A,\ i\in I. \tag{2}$$

Eq. (3) enforces an upper bound on the installed hydrogen import capacity linking to technical or policy-imposed limits on the maximum size of international hydrogen import infrastructure.

$$\underbrace{\bar{x}_{n,t,i}}_{H_2 \text{ capacity}} \le \underbrace{X^{\max}_{n,t,i}}_{\text{Upper bound}}, \quad \forall (n,t)\in A,\ i\in I. \tag{3}$$

Eq. (4) specifies the capacity constraint enforced on international hydrogen pipelines and terminals, ensuring that the hydrogen inflow through each entry point does not exceed its installed capacity.

$$\underbrace{y_{n,t,h,i,w}}_{H_2 \text{ inflow}} \le \underbrace{\bar{x}_{n,t,i}}_{H_2 \text{ capacity}}, \quad \forall (n,t)\in A,\ h\in H_s,\ i\in I,\ w\in W. \tag{4}$$

Eq. (5) specifies the hydrogen balance constraint at each node. On the supply side, imports through international pipelines and terminals, net pipeline flows, domestic production from electrolysis and reformers, and storage discharges are modelled. On the demand side, hydrogen use in power generation, steel, cement, ammonia, and refineries is represented as endogenous demand, while additional fixed demands for transport are captured as exogenous demand (see 2.2). Although EMPIRE allows for endogenous decisions in the production of cement, ammonia, and in refineries, these sectors have been fixed to correspond to exogenous hydrogen demand scenarios.

$$\begin{aligned}
&\underbrace{\sum_{(n,t)\in A} y_{n,t,h,i,w}}_{H_2 \text{ imports}} + \underbrace{\sum_{(n,n')\in N} \left(f_{n',n,h,i,w} - f_{n,n',h,i,w}\right)}_{H_2 \text{ pipeline inflow}} \\
&+ \underbrace{q^{\text{electrolyser}}_{n,h,i,w} + \sum_{p\in P} q^{\text{reform}}_{n,p,h,i,w}}_{H_2 \text{ production}} + \underbrace{\sum_{b\in B} s^{\text{discharge}}_{n,b,h,i,w} - \sum_{b\in B} s^{\text{charge}}_{n,b,h,i,w}}_{H_2 \text{ storage}} \\
&= \underbrace{c^{\text{power}}_{n,h,i,w} + c^{\text{steel}}_{n,h,i,w} + c^{\text{cement}}_{n,h,i,w} + c^{\text{ammonia}}_{n,h,i,w} + c^{\text{refinery}}_{n,h,i,w}}_{\text{endogenous } H_2 \text{ demand}} + \underbrace{C^{\text{exogenous}}_{n,h,i,w}}_{\text{exogenous } H_2 \text{ demand}},
\end{aligned} \tag{5}$$

$\forall (n,t)\in A,\ n\in N,\ b\in B,\ p\in P,\ h\in H_s,\ i\in I,\ w\in W.$

Lastly, as described in Eq. (6), all decision variables related to international hydrogen imports and associated system operation are constrained to be non-negative. This ensures that capacities, import volumes, pipeline flows, production, storage charging/discharging, and sectoral hydrogen consumption are modelled as non-negative quantities.

$$\begin{aligned}
&x_{n,t,j},\ \bar{x}_{n,t,i},\ y_{n,t,h,i,w},\ f_{n,n',h,i,w} \ge 0,\\
&q^{\text{electrolyser}}_{n,h,i,w},\ q^{\text{reform}}_{n,p,h,i,w} \ge 0,\\
&s^{\text{charge}}_{n,b,h,i,w},\ s^{\text{discharge}}_{n,b,h,i,w} \ge 0,\\
&c^{\text{power}}_{n,h,i,w},\ c^{\text{steel}}_{n,h,i,w},\ c^{\text{cement}}_{n,h,i,w},\ c^{\text{ammonia}}_{n,h,i,w},\ c^{\text{refinery}}_{n,h,i,w} \ge 0.
\end{aligned} \tag{6}$$

Electrolysis is modelled as a fixed 70/30 AEC/PEMEC technology mix using weighted averages for efficiency, cost, and lifetime. The split is an exogenous, representative assumption reflecting today's predominantly alkaline deployment with a modest PEM share for flexibility-oriented operation. Since ramping/availability constraints are not modelled, as they would not be binding at hourly resolution, it primarily affects techno-economic parameter values rather than operational dynamics.

The model retains existing SMR capacity while enabling endogenous expansion, with the associated CO_2 emissions included in the global emission constraint. Hydrogen transmission occurs via bidirectional pipelines that incorporate investment and O&M costs, and electricity for compression. Storage options cover location-specific underground salt caverns and compressed tanks, and seasonal carry-over has been implemented for underground hydrogen storage (UHS) in this study based on findings in Ref. [37]. Hydrogen-to-power is represented by investable CCGT, OCGT, and fuel-cell technologies with defined efficiencies and cost parameters.

Key assumptions appear in the Supplementary Materials, including details on green hydrogen import assumptions; further details on EMPIRE's hydrogen-supply modelling are given in [38].

2.1.2. Modelling of VRES growth limits

To ensure realistic VRES build-out trajectories, EMPIRE constrains onshore wind, offshore wind, and solar PV expansion through exogenous logistic-growth upper bounds. The logistic form captures the empirically observed S-curve of technology diffusion: rapid acceleration during market maturation followed by saturation as spatial, technical, and social limits appear [29]. Technical and spatial limits are derived from long-run resource potentials, while social constraints are represented implicitly through calibrated growth rates and scenario variants.

Country- and technology-specific growth rates r are estimated from historical annual VRES capacity deployment data (2000–2023) using IRENA Renewable Capacity Statistics 2024 [39]. For each node and technology, r has been calibrated by fitting the logistic deployment constraint in Eq. (8) to observed cumulative installed capacity. To reduce sensitivity to short-term fluctuations in the IRENA data, the historical dataset is smoothed using five-year rolling averages. The calibration is formulated as a nonlinear optimisation problem in which r is the decision variable and the objective minimises a weighted fit error between the logistic trajectory and the historical capacity series. Weights increase over time so that recent years have greater influence on the fitted growth rate. The optimisation is solved with r and fit quality metrics are recorded for each node.

Where historical deployment is too small to identify r reliably (e.g. capacity below a minimum threshold), missing r values are filled using capacity-weighted regional averages computed from nodes with successful fits. If a regional estimate is unavailable, a global fallback is applied. The resulting r values therefore reflect empirically observed build-out dynamics consistent with current VRES installation levels and recent expansion trends, while maintaining robust behaviour in nodes with limited historical deployment. The resulting r data is provided in Section 3 of the Supplementary Materials.

Long-run technical potentials K stem from the JRC ENSPRESO dataset reference scenarios [40,41]. To prevent implausibly large domestic build-outs, K is capped relative to 2050 electricity demand (including electrolysis): 120% for onshore wind, 200% for solar PV, and the full ENSPRESO potential for offshore wind.

The cumulative capacity bound $C(t)$ for country n and technology g is given by:

$$C_{n,g}(t) = \frac{K_{n,g}}{1 + \left(\frac{K_{n,g}}{C_{0,n,g}} - 1\right) e^{r_{n,g}\cdot(t_0 - t)}}, \tag{7}$$

where C_0 is the installed capacity in the base year ($t_0 = 2025$).

This is implemented in EMPIRE by enforcing that each investment period i, total cumulative VRES capacity cannot exceed the logistic upper bound $C^{\max}_{n,g,i}$:

$$\underbrace{\sum_{j\le i} x^{\mathrm{VRES}}_{n,g,j}}_{\text{Cumulative capacity}} \le \underbrace{C^{\max}_{n,g,i}}_{\text{Upper bound}}, \tag{8}$$

$\forall\, n \in N,\ g \in G,\ i \in I.$

Four growth variants are created by scaling the fitted rate r by factor α, producing alternative deployment scenarios (Section 3). These bounds render VRES expansion scenario-bounded endogenous, allowing EMPIRE to select least-cost mixes within empirically grounded trajectories.

2.2. Demand projections

This section summarises the demand projection models IndustryPLAN and TransportPLAN, which provide sectoral energy demands used in EMPIRE. Details on scenario combinations appear in Section 3.

2.2.1. IndustryPLAN

IndustryPLAN [32] is a freeware model representing industrial energy use through a hybrid bottom-up/top-down approach. It links disaggregated process-level demand to macroeconomic drivers such as GDP and technology diffusion, applying seven "energy-efficiency-first" principles [32]. The model quantifies energy use, CO_2 emissions, investment and fuel costs, and excess-heat potentials, producing outputs readily coupled with integrated models such as EMPIRE.

Two IndustryPLAN scenarios are applied: (i) Electrification-oriented, emphasising efficiency and direct electrification with minimal hydrogen use; and (ii) Hydrogen-intensive, assuming widespread hydrogen substitution for fuels. Together these form the low- and high-hydrogen industry trajectories. Feedstock hydrogen for hard-to-abate sectors not explicitly covered in IndustryPLAN are derived from previous EMPIRE studies [35,38].

TransportPLAN

TransportPLAN [33,34] is a back-casting tool for analysing transport decarbonisation pathways. It compiles detailed passenger and freight demand by mode and trip length, estimating traffic work, energy use, GHG emissions, and system costs. The model generates five-year interval scenarios to 2050 by varying five parameters: (i) transport-demand growth, (ii) modal-shift rates, (iii) technology shares, (iv) efficiency improvements, and (v) capacity utilisation — consistent with the Avoid/Shift/Improve framework [42]. TransportPLAN is not an optimisation model but a scenario generator whose outputs provide energy-demand projections compatible with energy-system tools such as EMPIRE.

Two contrasting transport scenarios are used and coupled with the industry scenarios: (i) Electrification-dominant, prioritising direct electrification of passenger and freight transport and restricting e-fuels to aviation and shipping; and (ii) Hydrogen/e-fuel-intensive, assuming broader adoption of hydrogen and e-fuels across modes. These represent low- and high-hydrogen transport trajectories.

2.2.2. Buildings and data centres

For the heating sector, we adopt the sEEnergies scenario [43], which assumes rapid VRES deployment, large-scale electrification, district-heating expansion, deep building renovation, and strong efficiency improvements. Residual electricity demands not covered by IndustryPLAN or TransportPLAN, including data centres, appliances, and cooling, follow projections from the ENTSO-E TYNDP 2024 [44]. The assumptions outlined in this subsection apply equally across the two demand scenario pathways used in this study.

3. Case study design

The scenario framework assesses Europe's green hydrogen import requirements along two dimensions: (i) the pace of VRES deployment, represented by logistic upper bounds (Section 2.1.2); and (ii) sectoral energy demand trajectories for hydrogen and electricity derived from IndustryPLAN and TransportPLAN (Section 2.2). Weather variability is treated endogenously in EMPIRE through stochastic multi-year data rather than as a separate scenario axis. For each case allowing international H_2 imports, a corresponding reference without import access (*Domestic H_2*) provides the baseline.

3.1. VRES deployment trajectories

Four logistic-growth variants define VRES expansion scenarios by scaling the intrinsic growth rate r by factor α while keeping the technical potential K constant (Section 2.1.2):

(a) **Low VRES** ($\alpha = 0.5$): slow build-out constrained by permitting, supply-chain, or social limits;
(b) **Historical** ($\alpha = 1.0$): continuation of recent trends;
(c) **Accelerated** ($\alpha = 1.5$): moderate policy-driven acceleration;
(d) **High VRES** ($\alpha = 2.0$): rapid scale-up enabled by strong policy and investment support.

Fig. 1 compares the resulting trajectories for solar PV, onshore, and offshore wind. The top panels show cumulative maximum capacity, and the lower panels the implied upper-bound annual build-out across all countries. Green curves indicate the four logistic bounds, with lighter shades denoting faster growth (α). The upper-bound data are applied directly in EMPIRE at nodal resolution. Annual build-out rates in the lower panels illustrate the acceleration necessary to achieve each upper-bound trajectory.

3.2. Hydrogen demand pathways

Two hydrogen demand pathways capture contrasting decarbonisation trajectories for Europe's industrial and transport sectors, consistent with the EU's 2050 climate-neutrality goal [45].

(1) **Low H_2 demand:** Direct electrification dominates wherever technically or economically viable. Hydrogen and e-fuels are confined to feedstocks and hard-to-electrify uses such as aviation and maritime transport. By 2050, electricity supplies ∼ 75% of industrial final energy; bioenergy and other low-carbon sources cover most of the remainder. Total hydrogen demand rises from ∼11 Mton/year in 2030 to ∼30 Mton/year in 2050, reflecting a complementary rather than central role for hydrogen.
(2) **High H_2 demand:** Hydrogen is widely adopted across end-use sectors. In industry, it provides ∼20% of final energy by 2050 (mainly high-temperature processes), with electricity ∼70% and bioenergy ∼10%. In transport, hydrogen and derived e-fuels dominate long-range freight, aviation, and shipping, and fuel-cell vehicles exceed half of passenger stock. Aggregate hydrogen use increases from ∼15 Mton/year in 2030 to ∼76 Mton/year in 2050.

The resulting sectoral trajectories are summarised in Table 2. These pathways serve as exogenous demand inputs to EMPIRE, defining two plausible pathways for hydrogen adoption in Europe's transition to climate neutrality. When hydrogen demand is implemented exogenously, EMPIRE assumes that end-use sectors have already adopted hydrogen technologies, and it focuses on determining the least-cost supply configuration to meet this demand.

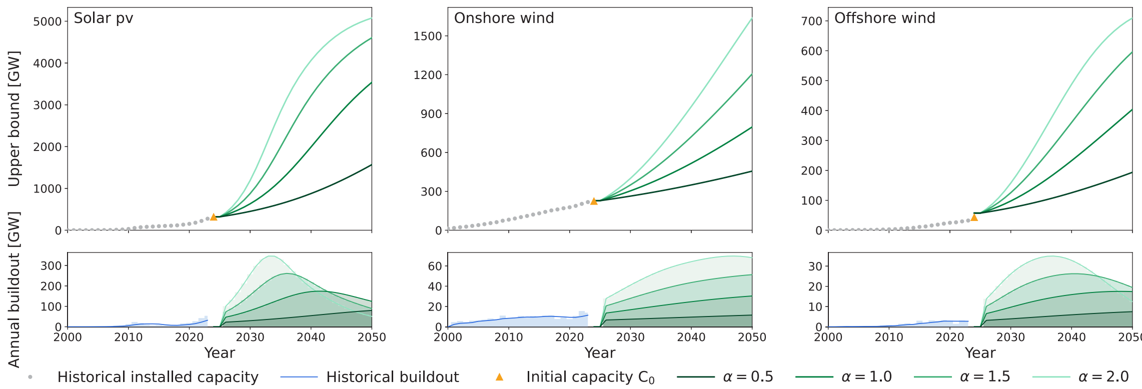

Fig. 1. Upper-bound trajectories (top) and indicative annual build-out rates to achieve upper-bounds (bottom) of solar PV, onshore wind, and offshore wind aggregated for all considered countries in Europe under four logistic growth scenarios. Grey dots and blue shading show historical capacity, blue lines depict 5-year rolling averages, orange markers indicate initial capacities (C_0), and green lines denote projected scenarios with lighter shades corresponding to higher growth rates (α). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Table 2
Annual H_2 demand by sector and scenario (Mton H_2/year), including indirect e.g. in e-fuel production.

Year	Low H_2			High H_2		
	Industrial	Transport	Total	Industrial	Transport	Total
2030	7.2	3.9	11.1	9.5	5.9	15.4
2035	6.5	9.3	15.8	12.7	17.8	30.5
2040	6.5	13.1	19.6	16.6	31.9	48.5
2045	6.2	17.3	23.5	20.2	43.5	63.7
2050	6.8	22.8	29.5	24.7	51.1	75.8

3.3. Key policy and system assumptions

A consistent set of policy and system assumptions is applied across all scenarios to ensure comparability. These reflect the current European targets, infrastructure developments, and technical constraints.

(i) **Decarbonisation:** All scenarios align with a CO_2 emissions cap that is consistent with the EU's objective of achieving climate-neutrality by 2050 [45].
(ii) **Hydrogen trade:** International H_2 imports are endogenously optimised, including pipeline and LH_2 terminal capacity (Section 2.1.1). Pipeline capacities from North Africa are limited, as per Ref. [46]. Nodes eligible for LH_2 terminals follow Refs. [47, 48]. Prices for international H_2 import are obtained from the TRACE model [49], assuming a discount rate of 7.5% with a sensitivity analysis of ±10%–30%. The data assumptions on H_2 imports are detailed in Section 2 of the Supplementary Materials, including numerical values provided in tables.
(iii) **E-fuel demand:** Projected e-fuel demands are represented by the hydrogen demand, transported and stored as hydrogen.
(iv) **Blue hydrogen:** Investments in SMR + CCS are excluded for simplicity but examined elsewhere [38]; SMR without CCS is permitted within the carbon budget.
(v) **Gas supply:** Russian pipeline imports cease from 2030; other routes (e.g., North Africa) remain available as well as LNG at premium cost [50].
(vi) **Biomethane:** Available at premium cost but is capped annually by resource potential adopted from [43].
(vii) **Coal phase-out:** National phase-out policies are enforced where announced [51].
(viii) **Oil refineries:** Production declines linearly to zero by 2050.
(ix) **Nuclear:** Expansion allowed from the discrete model year 2040, informed by recent projects (Olkiluoto-3, Flamanville-3, Hinkley Point C) [52]. Existing units retire after 60 years of operation based on commissioning data [53].
(x) **Demand flexibility:** Towards 2050, electrification of heating and transport provides system flexibility, reflecting smart charging, electric heating, and thermal storage [54]. It is assumed that 33% of electricity for heating and transport can operate flexibly within an interval range of 0%–150% of the given hourly demand.
(xi) **Temporal and weather resolution:** The model spans 2025–2055 in five-year steps, and applies a 5% discount rate. Each period includes four seasonal weeks and two peak days (i.e., 720 h × five stochastic weather years, equally weighted), following [31]. A single weather sampling ensures comparability across scenarios.

Together these assumptions define a coherent, context linked framework for assessing hydrogen demand and VRES deployment trajectories across Europe.

4. Results

This section presents model results for Europe's energy system transition under alternative VRES deployment and hydrogen demand scenarios for 2030–2050. The analysis highlights how the pace of VRES expansion and sectoral demand influence the scale and timing of green hydrogen imports. Results are discussed across five dimensions: (i) hydrogen and electricity supply developments, (ii) weather-induced variability in hydrogen imports, (iii) net present value comparison, (iv) spatial system configurations, and (v) import price sensitivity.

4.1. Hydrogen and electricity supply developments

Fig. 2 shows the expected hydrogen and electricity balances, averaged across five stochastic weather years. The results illustrate a strong interdependence between VRES expansion, electrolysis deployment and production, and import dependence. Accelerated growth of VRES facilitates a largely domestic hydrogen supply well before mid-century, aligning with Europe's ambitions for energy independence. Under historical growth rates, international imports offer the least-cost near-term option, supporting a faster phase-out of SMR hydrogen but prolonging energy import exposure. If VRES expansion stalls and hydrogen remains critical for decarbonisation, Europe will become predominantly dependent on imports. 0.4543 0.55

Detailed scenario outcomes and system responses for each VRES and demand variant are described in the following subsections.

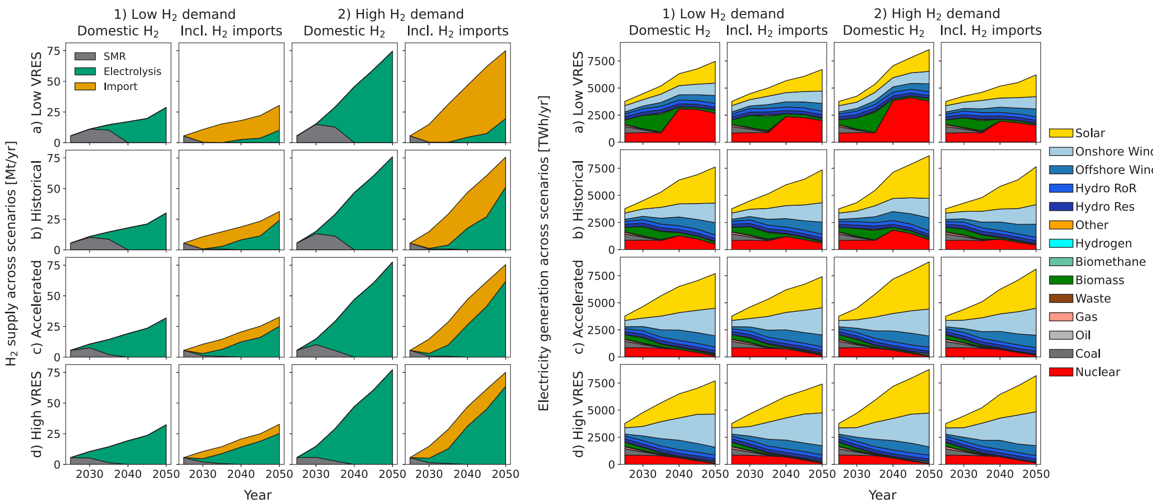

Fig. 2. (Left) Evolution of hydrogen supply composition across scenarios during 2030–2050 (Mton/year), and (Right) electricity generation by technology across hydrogen demand and VRES scenarios (TWh/year). In both panels, rows (a–d) show Low, Historical, Accelerated, and High VRES growth; columns compare Low vs. High hydrogen demand and Domestic vs. Import cases.

4.1.1. Low VRES growth - (a)

Limited VRES deployment restricts the cost-effectiveness of electrolysers in Europe, resulting in minimal domestic hydrogen production throughout the period. Under the high hydrogen demand pathway, electrolysis accounts for only ~25% of total hydrogen supply by 2050, while 33% is supplied in the low demand scenario. Imports therefore dominate, providing 66%–75% of total supply across both demand pathways. In the corresponding *Domestic* H_2 case, the system initially compensates through extensive SMR operation until 2035–2040, after which electrolysis replaces the fossil hydrogen to meet demand due to the carbon constraint in the model. Therefore, if VRES deployment stalls and hydrogen ambitions persist, Europe will become dependent on international imports. If Europe want to achieve self-sufficiency under these conditions, it will rely on large-scale thermal power-based electrolysis, such as bioenergy and nuclear. Under the high-demand scenario, this would require roughly a three- to fivefold increase in nuclear capacity by 2050, marking a relatively extreme expansion that currently appears practically and politically doubtful, especially for the purpose of supplying electrolysis. It is worth noting that this study applies upper bounds on VRES deployment, but no upper bounds are assumed for nuclear reactor deployment or other thermal power plants or biomass availability. However, these generators are subject to practical limitations that this study does not capture. In this restricted scenario, these thermal power plants serve more as a system backstop to meet the balance constraints, with an absence of more effective CO_2-neutral alternatives. Although not modelled in this study, hydrogen from SMR combined with CCS could likely reduce system cost in this case [55], though at the expense of higher natural gas demand, reinforcing import reliance, and expanded CO_2 storage requirements. With this in mind, the scenario without international imports ultimately achieves hydrogen self-sufficiency but incurs substantially higher system costs than in the subsequent scenarios with increased VRES deployment (see Section 4.2).

4.1.2. Historical VRES growth - (b)

Following historical VRES deployment trends enables electrolysis to expand steadily from 2035–2040. Between 2040 and 2045, imports supply ~53% of European hydrogen demand in the low demand scenario and ~60% in the high demand scenario. In the low demand scenario, imports from North Africa account for ~60% of total imports across the entire planning period; in the high demand case this share is ~40% as LH_2 terminals provide a greater fraction. The higher relative share from North Africa in the low demand case reflects capacity constraints (Section 3.3) and lower import prices. By 2050, electrolysis supplies 68%–77% of hydrogen across the demand pathways, due to growing VRES deployment. Imports allow faster SMR phase-out than in the *Domestic* H_2 scenarios, where bioenergy and nuclear capacity expansion becomes a lever to offset missing imports and VRES. The resulting electricity mix combines VRES, nuclear, and other thermal power. This trajectory aligns with observed VRES growth trends, exhibiting short-term dependence on imports while maintaining high to moderate import reliance through the 2030s and 2040s.

4.1.3. Accelerated VRES growth - (c)

With faster VRES deployment, electrolysis becomes the dominant hydrogen source well before mid-century. Imports cover ~18%–23% of total supply by 2050, and SMR is eliminated by 2040. The power system shifts structurally: VRES generation exceeds all other sources combined by 2030–2040, while bioenergy, and hydro provide mainly balancing capacity. Electrolysis and hydrogen storage enable VRES integration, and nuclear additions remain minimal. This pathway combines deep decarbonisation with declining import dependence while retaining system flexibility.

4.1.4. High VRES growth - (d)

Under the most ambitious VRES deployment trajectory, the energy system achieves an electrolysis-to-import ratio similar to the accelerated case by 2050 but diverges earlier, where higher VRES growth displaces hydrogen imports. Between 2030 and 2040, imports supply ~45% of total hydrogen in the high demand scenario and ~39% in the low demand case, compared with ~52%–57% under the accelerated growth scenario. Rapid onshore-wind expansion on top of solar PV drives this outcome, enabling solar and wind to dominate power generation, complemented by dispatchable hydro and bioenergy, while nuclear expansions are minimal. This scenario delivers the strongest combination of decarbonisation and energy independence but presupposes unprecedented VRES deployment.

4.1.5. Hydrogen demand scenarios

Table 3 summarises expected hydrogen imports across VRES deployment and demand scenarios. In many cases, imports peak around 2045 before stabilising or declining as VRES capacity continues to expand. Under the *Low VRES* trajectory, imports remain persistently high, reaching ~20 Mton H_2/year by 2050 in the low demand case and ~55 Mton H_2/year under high demand. With historical growth, imports plateau earlier but still exceed 20 Mton H_2/year by mid-century in the

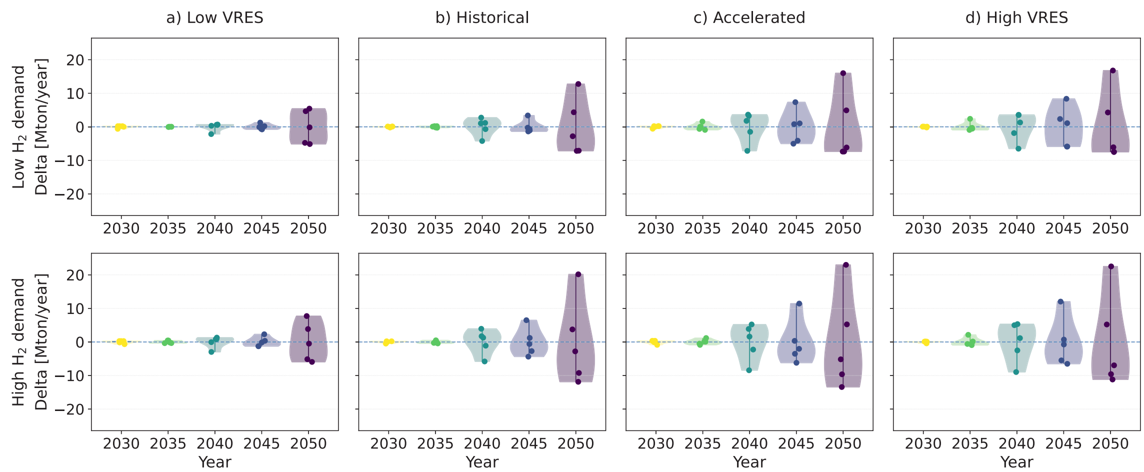

Fig. 3. Annual deviations in hydrogen imports relative to the mean across five stochastic realisations for each combination of hydrogen demand (rows) and VRES growth rate scenario (columns). Each dot represents one stochastic realisation. The *y*-axis shows deviations in Mton H_2/year, where zero corresponds to the mean import level for each year and scenario (Table 3). Positive values indicate years with above-average import requirements due to low VRES availability, while negative values represent surplus domestic production under favourable wind and solar conditions.

Table 3
Expected (mean) hydrogen imports by VRES growth rate scenario and demand pathway (Mton H_2/year). The left group represents low hydrogen demand scenarios, and the right group represents high demand scenarios. The final row, denoted as R_{imp}, shows the cumulative import index across all periods, expressed relative to the scenario with the lowest cumulative import (set to 1.0).

Year	Low H_2 demand				High H_2 demand			
	Low VRES	Historical	Accelerated	High VRES	Low VRES	Historical	Accelerated	High VRES
2030	10.4	10.0	7.6	5.9	14.5	13.7	11.7	9.7
2035	15.3	11.9	8.2	5.6	30.9	25.3	18.7	15.9
2040	15.5	10.6	8.2	6.6	42.2	29.1	20.7	15.8
2045	18.4	11.9	9.1	6.0	54.5	33.5	20.1	16.3
2050	20.3	7.3	7.5	7.6	55.3	24.4	13.6	11.4
R_{imp}	*2.5*	*1.6*	*1.3*	*1.0*	*6.2*	*4.0*	*2.7*	*2.2*

high demand pathway; while they decline to ~7.5 in the low demand pathway.

In contrast, the *Accelerated* and *High VRES* scenarios show rapid substitution of imports with domestic electrolysis, cutting requirements to below 14 Mton H_2/year by 2050 under high demand and to ~7.5 Mton/year under low demand. The *High VRES* pathway reduces import dependence more effectively than the *Accelerated* case, particularly between 2030 and 2040 across both demand scenarios.

These trajectories highlight how the timing and scale of VRES deployment influence import dependence. Faster VRES build-out both postpones and reduces the import peak, whereas slower expansion locks the system into prolonged external reliance. Projected 2030 import volumes (10–14 Mton H_2/year) for both low and historical VRES growth scenarios are comparable to or exceed the REPowerEU target of 10 Mton H_2 imports. This suggests that early reliance on imports can align with decarbonisation and gas phase-out objectives. However, under a scenario of accelerated or high VRES growth and low hydrogen demand, imports fall well below this target, indicating that rapid VRES expansion alongside direct electrification is an effective strategy to substantially decrease import requirements.

Overall, increased deployment of VRES reduces dependence on international hydrogen markets. Without this acceleration, import dependency will persist beyond 2040, potentially constraining Europe's ambition for strategic autonomy in the sustainable energy transition.

4.1.6. Weather-induced variability in hydrogen imports

To assess the robustness of the scenario results against inter-annual weather variability, five stochastic realisations were evaluated for each combination of VRES deployment and hydrogen demand scenarios. The stochasticity affects only the hourly load, hydro power potentials, and capacity factors for onshore wind, offshore wind, and solar generation; all investment and network configurations remain constant across the corresponding realisations through joint optimisation. These weather variations affect both domestic electrolysis output and the consequent hydrogen import requirements.

Fig. 3 shows, for each year and scenario, the distribution of deviations in annual hydrogen imports relative to the same-year mean (as presented in Table 3). Two key insights emerge: (i) In the early period (2030–2040), deviations remain limited because electrolyser fleets are small and less sensitive to weather. (ii) From 2040 to 2050, variability grows substantially as electrolysis capacity expands and import requirements fluctuate critically with VRES output. Hydrogen imports increase in stochastic scenarios with relatively lower VRES capacity factors, and imports decrease in stochastic scenarios with relatively higher VRES capacity factors, displaying a clear relationship between VRES availability and hydrogen imports. Furthermore, the magnitude of weather-induced impacts increases over time as hydrogen demand rises and the system becomes more critically exposed to VRES variability.

As an example, in 2050 under the *Low Demand–Accelerated VRES* scenario, the mean import level is 7.6 Mton H_2/year, yet stochastic outcomes range from near zero to ~23.5 Mton H_2/year import levels. This suggests that an unfavourable weather year can triple import needs, even when average imports are moderate. This underscores the importance of international supply as a buffer against inter-annual volatility in VRES availability.

The apparent magnitude of this spread should, however, be interpreted cautiously, as structural simplifications in the model tend to amplify short-term fluctuations. EMPIRE does not model inter-annual seasonal hydrogen storage; annual storage balancing is enforced separately within each stochastic scenario, preventing surplus production in favourable years from being shifted to deficit years. Nevertheless,

Table 4
Total system objective value (net present value) by VRES growth rate scenario and demand pathway (billion €). Values in parentheses show relative cost savings (%) from allowing international hydrogen imports compared with the corresponding Domestic H_2 case.

[Bn €]	Low H_2 demand		High H_2 demand	
VRES scenario	Domestic H_2	International H_2	Domestic H_2	International H_2
Low VRES	8388	8160 (−2.7%)	8985	8336 (−7.2%)
Historical	7870	7770 (−1.3%)	8315	7981 (−4,0%)
Accelerated	7621	7558 (−0.8%)	7960	7799 (−2.0%)
High VRES	7493	7449 (−0.6%)	7825	7707 (−1.1%)

this still captures a potential vulnerability, because storage operations are not deterministic by nature, and multi-year exposures may arise. Second, each investment period is represented by a limited number of seasonal weeks and peak days, which limits the ability to fully capture the intra-seasonal diversity of VRES output. As a result, weeks with extreme weather conditions may be assigned a higher effective weight than their actual likelihood of occurrence over an entire season.

In practice, these factors could be mitigated by additional flexibility from overcapacity in storage infrastructure, enabling inter-annual balancing. Thus, the upper tail of the stochastic distribution in Fig. 3 should be interpreted as an indicator of potential vulnerability under limited balancing capability, rather than as a literal year-to-year volatility projection.

Taken together, these findings underline that inter-annual weather variability can substantially influence hydrogen import needs, especially as electrolysis and VRES capacities scale. While the absolute magnitude of import fluctuations partly reflects model simplifications, the direction of the effect is robust: systems with higher VRES penetration necessitate more robust balancing mechanisms to maintain supply stability. The results therefore highlight the strategic value of international hydrogen trade as a diversification option and underscore the importance of developing long-duration buffer storage and cross-sectoral flexibility to hedge against weather-related volatility in a future dominated by variable VRES.

4.2. Net present value comparison

Table 4 summarises total system costs across all VRES deployment and hydrogen demand scenarios, showing that access to international hydrogen imports consistently lowers overall costs. The magnitude of these savings, however, depends strongly on VRES expansion. Under the *Low VRES* scenario, where limited VRES restrict electrolysis and the system compensates through extensive nuclear deployment, hydrogen imports yield the largest benefit, reducing total costs by up to 7% under high hydrogen demand. As VRES growth accelerates, the marginal value of imports diminishes, resulting in savings of less than 1% in the *High VRES-Low demand* scenario. This reflects a clear *import–VRES substitution effect*: the gradual expansion of domestic VRES increasingly displaces the role of international imports in satisfying hydrogen demand and balancing system operation. Rapid VRES deployment therefore not only advances energy self-sufficiency but also achieves the highest long-term economic efficiency, whereas slower expansion locks the system into costlier configurations more prone to import dependencies.

Cost differences between hydrogen demand scenarios further show that relative savings from imports are consistently larger under *High H_2 demand*. International trade thus becomes most valuable when domestic VRES and electrolyser capacity cannot fully meet rapidly growing hydrogen needs. Nonetheless, the *Low H_2 demand* pathways, driven by increased direct electrification, remain overall more cost-effective. However, this comparison should be interpreted with caution, as the analysis focuses on the coupled power, hydrogen, and gas markets within the EMPIRE energy system model and does not capture related downstream or value-chain costs beyond those explicitly represented. However, numerous studies suggest the same. For example, Refs. [33,34] find this to be the case for the Danish and European transport sectors, while Refs. [56–58] conclude the same for the European industrial sectors, and Refs. [43,59] further support this conclusion through studies of integrated energy systems encompassing all demand sectors on a European scale.

In summary, international hydrogen imports act as a transitional lever to reduce near-term costs and supply constraints, but their strategic relevance diminishes as VRES capacity expands and domestic production scales. The next subsection examines how these dynamics manifest spatially through evolving hydrogen and power generation patterns, cross-border flows, and infrastructure utilisation under the contrasting VRES scenarios.

4.3. Spatial system configurations

Fig. 4 illustrate how VRES deployment and import corridors shape the spatial configuration of hydrogen supply, transport, and storage across the four VRES growth scenarios and both demand pathways.

Across all scenarios, electrolysis clusters where VRES and UHS potentials are co-located. In the *Historical* scenario, large solar PV potential and strong historical growth trends, combined with extensive salt-cavern storage potentials, positions Spain as significant H_2 supplier and net exporter. Under the *Accelerated* and *High VRES* scenarios, the increasing diffusion of solar PV and onshore wind across countries such as France, Italy, and Great Britain shifts production closer to central Europe, where UHS potential is also high, and proximity to key net-importing regions reduces the length of transmission pipelines.

As VRES growth accelerates, hydrogen supply becomes increasingly decentralised across Europe, reducing cross-border trade volumes compared to the *Historical* scenario. The underlying assumption that VRES growth scales equivalently across European borders is a simplification, however increasing onshore wind availability on top of high solar PV availability across Europe leads to more geographically distributed supply hubs. This lessens the requirement for long-distance power and hydrogen transmission, though key corridors remain, especially across central and western Europe.

In the *Low VRES* scenario, limited VRES generation constrains power balances and distributes hydrogen production across the continent. Spain and Germany are leading producers, closely followed by France, Great Britain and the Netherlands. A practical realisation of this particular outcome is, related to high uncertainty, and a hydrogen import pathway presents greater economic advantages in this context (see 4.2).

Where the lower map in Fig. 4 shows persistently tight power balances (lower generation output and/or net power inflows), the upper map shows higher H_2 inflows via international corridors and terminals. In the *Low VRES* scenario, these imports dominate the supply mix, offsetting otherwise necessary investments in thermal-power-based electrolysis, such as nuclear or bioenergy, which serve as a more expensive backstop within the modelled system. With faster VRES expansion, European self-sufficiency increases, although reliance on imports varies by region.

In the *Accelerated* VRES case, seven nodes — Italy, the Netherlands, Belgium, Estonia, Romania, Poland and Great Britain — import more international H_2 than they produce domestically. Under the *High VRES* trajectory, this group narrows to three: Italy, Romania and the

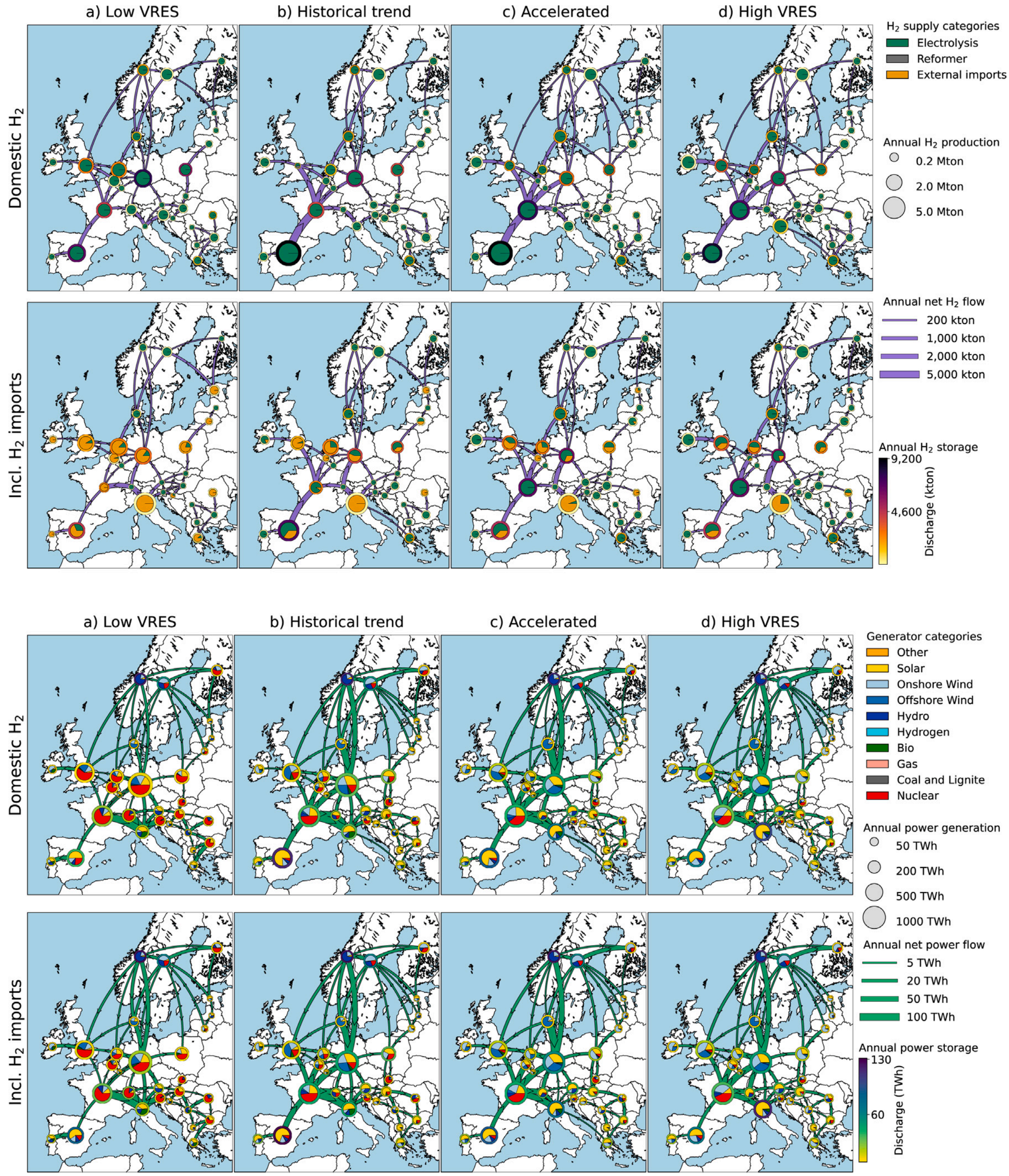

Fig. 4. Spatial distribution of (top two rows) hydrogen supply and (bottom two rows) power supply across scenarios for the European energy system in 2040 under the Low H_2 demand pathway. Each column represents one VRES deployment scenario (a–d: Low VRES, Historical trend, Accelerated, and High VRES). The first row of the hydrogen and power maps respectively, show the domestic hydrogen supply scenarios, whereas the second rows show the import scenarios. Node pie-chart size indicates annual hydrogen an power supply and line thickness represents annual net H_2 and power flows, with arrows indicating the direction. Halos surrounding production charts indicates annual hydrogen and power storage discharge.

Netherlands, where imports remain dominant. Spain, Belgium, Estonia and Great Britain continue importing more than one-fourth of their total hydrogen supply, excluding intra-European flows. In both Italy and Spain, pipeline imports from North Africa, which are lower-cost compared to coastal LH_2 terminals, sustain a significant import corridor that also supplies central Europe, with both countries functioning as transit points to the region.

Overall, the spatial patterns indicate that by the availability of VRES, electrolysis increasingly aligns with national VRES and storage potentials, thereby reducing the scale of both international and intra-European hydrogen trade; nevertheless, trade continues to play a critical role in achieving long-term targets. The persistence of a few strategic import corridors, particularly from North Africa, highlights that even in highly VRES futures, targeted international connections remain economically valuable. These results underscore that Europe's pathway to hydrogen self-sufficiency will depend not only on the overall pace of VRES deployment but also on coordinated spatial planning of electrolysis capacity, storage, and cross-border infrastructure to balance regional disparities in resources and demand. However, an essential dimension that could significantly impact hydrogen infrastructure requirements is the e-fuels supply chain, which remains unexplored in

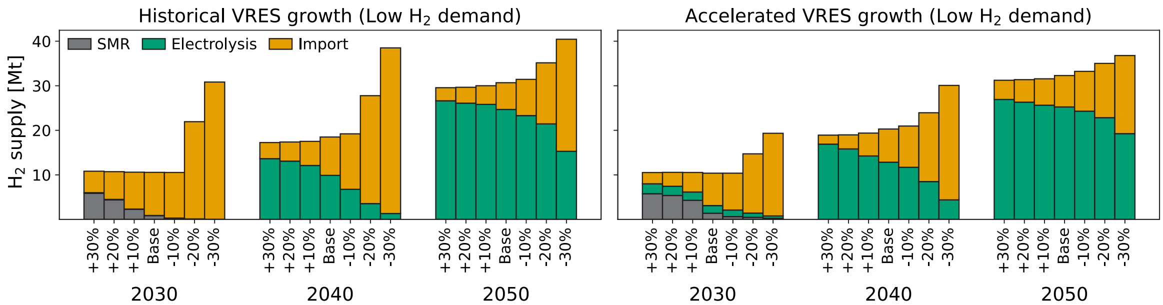

Fig. 5. Hydrogen supply by source and ±10%–30% import price variants for 2030, 2040 and 2050, for the Historical (left) and the Accelerated (right) VRES growth scenario for the Low H_2 pathway. Inter-annual differences hydrogen demand reflect endogenous hydrogen demand for power generation.

this study. E-fuels are technically and economically favourable for storage and transport due to their high energy density, whereas hydrogen requires more extensive processing.

4.4. Sensitivity analysis on hydrogen import prices

Fig. 5 shows the sensitivity to hydrogen import prices in the Historical and Accelerated VRES growth scenarios under the Low Hydrogen demand scenario. Introducing a price variation of ±10%–30% to the base case demonstrates sensitivity in the results regarding H_2 price assumptions, particularly towards lower import prices. At price assumptions 20%–30% lower than the baseline, imports start to dominate the least costly European hydrogen supply between 2030 and 2040. Hydrogen at these price levels drives demand upward, as additional hydrogen is used endogenously in the power and steel sector; primarily competing with other thermal power plants, such as bioenergy, natural gas, and nuclear power plants, since VRES growth is constrained. The import price sensitivity is generally lower in the Accelerated VRES growth scenario, and in both scenarios it weakens towards 2050, correlating with the availability of VRES deployment in Europe.

5. Discussion

This study quantifies how Europe's VRES deployment trajectory and end-use transition pathway determine the scale, timing, and strategic role of green hydrogen imports. The results highlight strong interdependencies between VRES expansion, low system costs, and import dependence across all scenarios.

The findings of this study suggest that meeting the REPowerEU plan's 2030 targets of 10 Mton domestic hydrogen supply and 10 Mton imports may prove challenging. This is best exemplified by the *High H_2 demand* scenario in this study, in which the European hydrogen demand reaches 20 Mton by 2032, corresponding to the REPowerEU demand targets for 2030. Under constraints on VRES deployment, CO_2 emissions and gas imports, our results indicate that a combination of hydrogen imports and continued fossil-based hydrogen provides the least-cost solution to meet the short-term demand, as available VRES is more valuable when used to displace fossil power generation than to serve new hydrogen demands. Only in the *High VRES* scenario does domestic electrolysis significantly contribute in the short to medium term. This suggests that the emergence of a large-scale European hydrogen economy may be slower than current plans, although early agreements with international trading partners can still support capacity building early on. Overall, in none of the scenarios does short-term domestic electrolysis production reach the targets set by the REPowerEU plan.

The results of the study further demonstrate that an alternative decarbonisation strategy for end-use applications can substantially alleviate hydrogen-related supply pressures. In the *Low H_2 demand* pathway, which emphasises direct electrification and energy efficiency, policy targets for decarbonisation and phaseout of Russian gas are achieved with substantially lower hydrogen import requirements. This suggests that policies which prioritise direct electrification in sectors where it is technically and economically feasible, while reserving hydrogen for hard-to-abate applications, can ease short-term supply and infrastructure pressures and reduce reliance on imports. In this context, revisiting hydrogen volume targets and focusing on areas where hydrogen provides the highest system value can provide a more robust strategy compared to REPowerEU.

The growth rates of VRES are identified as another key factor influencing import requirements. Even moderate acceleration beyond historical build rates significantly reduces import dependence and lowers overall system costs. The analysis shows that transitioning from the *Historical* to the *Accelerated* VRES scenario reduces cumulative hydrogen imports by 22%–33% and significantly diminishes structural import requirements. In the *High VRES* trajectory, structural import dependency can largely be eliminated throughout the entire planning period. Energy independence and decarbonisation emerge as mutually reinforcing objectives, as rapid VRES deployment reduces vulnerability to global hydrogen markets and provides a cost-effective pathway. Conversely, low VRES growth hindered by permitting-, social-, or supply-chain barriers could lead Europe towards a costlier and geopolitically sensitive dependence on imports.

Effectively addressing the energy trilemma requires overcoming barriers to the deployment VRES. Future VRES trajectories will depend on the EU, European states, and local governments' ability to reform planning practices to reduce permitting times while effectively addressing citizens' concerns. When planning processes fail, local resistance often follows, leading to project delays or cancellations. In our scenarios, moving from *Low* to *High VRES* results in significant 8%–13% savings in the net present value of system costs throughout the planning period, highlighting the economic rationale for addressing these bottlenecks. Thus, VRES remains the most cost-effective lever for decarbonisation and reducing import dependence; however, this potential can only be realised if European stakeholders negotiate the trade-offs between increased energy independence and more intensive domestic infrastructure, while adapting planning and participation mechanisms accordingly.

While accelerated deployment of VRES and a more targeted use of hydrogen significantly reduce structural import dependence, the results indicate a continued strategic role for international hydrogen trade. The stochastic simulations show that inter-annual weather variability can lead to significant fluctuations in domestic hydrogen production after 2040, when electrolysis becomes the dominant production route. Although the model may overestimate the magnitude of this spread, the implication is that VRES-heavy systems must enhance flexibility through long-duration storage, demand-side flexibility and regional coordination. In this context, international hydrogen imports, particularly when combined with long-duration storage, act as a structural hedge against inter-annual variability in VRES output. Their marginal value declines as VRES capacity expands, but they retain strategic importance in the long term. In earlier years, when VRES availability and electrolyser capacity remain constrained, imports substitute for fossil SMR-based hydrogen and help bridge delays in domestic scaling. Developing international trade infrastructure early in response to domestic capacity shortages can therefore preserve long-term option value, even in scenarios that approach self-sufficiency.

Taken together, the results suggest that Europe's energy independence will hinge on accelerated VRES deployment and coordinated planning of electricity, hydrogen demand and supply, and infrastructure. Within such a system, hydrogen trade is best understood not as a permanent supply pillar, but as a tool for short-term capacity building and long-term diversification in an increasingly weather-dependent VRES-dominated system.

5.1. Limitations and future research

This study has several limitations that point to future research. We do not model domestic blue hydrogen (SMR+CCS). Allowing hybrid strategies that combine green and blue hydrogen could improve transitional robustness by diversifying supply and easing VRES constraints. E-fuel end-uses are represented only as hydrogen demand in EMPIRE, with storage and transport modelled as hydrogen. Explicitly integrating CO_2 utilisation, e-fuel pathways and e-fuels as import vectors would expand the system boundaries, and capture interactions between hydrogen, CCUS and e-fuel infrastructure, and may reveal more cost-effective transport options than long-distance hydrogen pipelines.

Although EMPIRE includes cross-border transmission, intra-zonal grid reinforcement is not modelled in detail. Cross-border expansions use linear MW/km cost functions based on centroid-to-centroid distances, which likely underestimate grid needs.

While electricity, natural gas and hydrogen demands across all sectors are included, sector coupling is simplified. Flexibility in heating and transport is represented through stylised measures (see Section 3) rather than a fully integrated sector-coupled framework, which could better quantify the role of green hydrogen infrastructure in providing flexibility relative to other options.

Finally, hydrogen import prices are treated deterministically and explored further through sensitivity analysis. Using stochastic or CVaR-based formulations and coupling EMPIRE with global hydrogen trade models could better capture price volatility and geopolitical risk and support more robust, risk-averse infrastructure strategies.

6. Conclusion

This study examines European hydrogen import requirements for the energy transition over the period 2025–2050. It contributes to the existing literature by introducing a novel modelling framework that links end-use sector modelling, logistic scenarios capturing S-curve trends in VRES growth, and stochastic optimisation of inter-annual weather variability to address substantial demand and supply uncertainties.

Specifically, we combine two hydrogen-demand scenarios with four variations in upper-bound VRES deployment trajectories. The high-demand scenario assumes widespread hydrogen use for energy applications, while the low-demand scenario prioritises direct electrification. The VRES trajectories are derived from 20 years of European deployment data and represent four growth paths: low, historical, accelerated, and high.

We find that Europe's requirements for green hydrogen imports depend strongly on the pace of VRES expansion and the adoption of decarbonisation measures in end-use, and we suggest a more robust alternative to the REPowerEU targets. This makes our results highly relevant for policy-makers navigating the energy trilemma of sustainability, security of supply, and affordability.

Our findings show that faster VRES deployment combined with a direct electrification-first strategy substantially reduces import requirements and overall system costs, thereby alleviating all three dimensions of the energy trilemma. Under a scenario with high electrification rates and historical VRES growth trends, we estimate a cost-optimal import level of ~7.5 Mton by 2050, corresponding to ~20% of European hydrogen demand. This cost-optimal 2050 import level remains similar under accelerated and high VRES growth assumptions; however, in these cases, cumulative imports over 2030–2050 fall by up to ~38% due to faster VRES diffusion coupled with domestic electrolysis. In contrast, if VRES deployment stalls, Europe depends on international imports for roughly two-thirds of its hydrogen supply even under low-demand assumptions. Import requirements rise further in the high-demand scenario, reaching ~25 Mton by 2050 under historical VRES growth, effectively tripling imports relative to the direct electrification scenario.

Our study suggests that international hydrogen imports can provide a role as short-term capacity to meet demand targets and a long-term hedge against adverse weather years. However, their intrinsic value and structural role diminish if domestic VRES and electrolysis scale-up can be achieved. VRES expansion is the primary driver of a least-cost, decarbonised European energy system with a high degree of energy independence. Additionally, hydrogen infrastructure, such as cross-border pipelines and long-duration storage, can play a crucial role; however, transportation and storage of e-fuels have not been explored in this study, but they likely offer more effective solutions compared to processing-heavy hydrogen solutions.

Overall, our results indicate that Europe's most robust path to a least-cost, low-carbon, and energy-independent system is to prioritise rapid VRES deployment and direct electrification, with hydrogen imports playing a supplementary role in short-term capacity building and long-term diversification of supply.

CRediT authorship contribution statement

Frederik Dahl Nielsen: Writing – original draft, Visualization, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Stian Backe:** Writing – review & editing, Supervision, Software, Conceptualization. **Benjamin Mitterrutzner:** Writing – review & editing, Conceptualization. **Pedro Crespo del Granado:** Conceptualization.

Declaration of generative AI and AI-assisted technologies in the manuscript preparation process

During the preparation of this work, the author used Overleaf's integrated language model feature to improve the readability. After using this tool, the author reviewed and edited the content as necessary and assumes full responsibility for the content of the published article.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

This work was supported by the European Union's Horizon Europe Research and Innovation programme under Grant No. 101095849, as well as the Nordic Hydrogen Hubs – Roadmaps towards 2030 and 2040 project, which is part of the Nordic Hydrogen Valleys as Energy Hubs programme, with funding from Nordic Energy Research, Norway. Moreover, B.M. acknowledges the Research Council of Norway for funding his PhD through the research center 'LowEmission' [Project No. 296207].

Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.ijhydene.2026.154457.

Data availability

Key data assumptions are provided in Supplementary Materals and the code and input datasets used in this study is available in the following open-access repository:

https://github.com/frederikdn/EMPIRE_H2Imports.

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