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Green hydrogen from renewables: a simulation and sensitivity study

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Abstract
Green hydrogen, produced through water electrolysis powered by renewable energy, is emerging as a cornerstone of low-carbon energy systems. This paper develops a simulation framework that integrates solar and wind variability, electrolyzer operational constraints, cost modeling, and carbon accounting. In a baseline 100 MW case with mixed solar–wind input, the system achieves a proxy LCOH of $2/kg and net abatement of 0.5 Mt CO_2 over 26 years. A parametric analysis was conducted, revealing a strong sensitivity of the yields to electrolyzer efficiency, specific energy consumption, and renewable scaling. Efficiency improvements from 0.60 to 0.80 reduced LCOH by 25–30%, while a 20% renewable overbuild raises hydrogen output by 30–40 kt/yr. These results demonstrate that coordinated improvements in electrolyzer performance and renewable deployment are essential to move green hydrogen toward cost parity with grey hydrogen and to meet net-zero 2050 targets.

Keywords: *Green Hydrogen; Renewable Energy; Energy Geotechnics; Simulation Modeling; Sensitivity Analysis*

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I. Introduction

Hydrogen is increasingly recognized as a central element in achieving net-zero energy systems (Arinze, 2025; Turner, 1999). It offers unique advantages as a clean energy carrier: it can be produced from renewable electricity, stored over long periods, transported, and converted back into power or used directly in industrial processes (IEA, 2019; Staffell et al., 2019; Hepburn et al., 2020; Canton and Lindberg, 2021; Ajanovic and Haas, 2021; Zheng and Xu, 2021; Bailera et al., 2017; Glenk and Reichelstein, 2019; Fasihi et al., 2016; Ramachandran and Menon, 1998). However, global hydrogen production remains overwhelmingly dependent on fossil fuels, with steam methane reforming (SMR) and coal gasification accounting for more than 95% of supply (IRENA, 2020; Dutta, 2014; Leung et al., 2014; DOE, 2020; Wang, 2011).

Figure 1 shows the production path for hydrogen, including conventional and renewable alternative energy sources. These conventional pathways emit large quantities of CO_2, making hydrogen production a significant source of greenhouse gas emissions unless paired with carbon capture and storage (Bicer et al., 2018; Glenk and Reichelstein, 2019; Leung et al., 2014). Conventional production is currently over 800 Mt CO_2 annually (IEA, 2021), while low-carbon and green hydrogen account for less than 1% of the supply (Bains et al., 2023; Remme et al., 2024).

Green hydrogen, while still a subset of hydrogen production, specifically refers to hydrogen generated through the electrolysis of water using renewable electricity, avoids direct CO_2 emissions and is therefore central to sustainable energy transitions (Olabi and Wilberforce, 2023; Boretti, 2024). In addition to decarbonizing hydrogen production, it can integrate with variable renewable energy (VRE) systems by absorbing excess power, providing a form of long-duration storage, and contributing to grid balancing. These features make hydrogen not only an energy product but also a system enabler in high-renewables scenarios.

Despite this promise, the deployment of green hydrogen faces major challenges. Electrolyzers are still capital intensive, electricity costs dominate production costs, and the intermittency of solar and wind resources complicates operational planning (Zeng and Zhang, 2010; Saba et al., 2018). Previous studies have advanced techno-economic assessments of hydrogen production (Glenk and Reichelstein, 2019), analyzed the role of hydrogen in energy storage (Blanco and Faaij, 2018), and explored life cycle impacts (Staffell et al., 2019). However, there remains a gap in integrated frameworks that connect renewable generation, electrolyzer operation, cost and emissions accounting, and scenario analysis in a manner suitable for comparative simulation studies.

The objective of this study is to develop an integrated simulation framework that quantifies hydrogen yield, avoided emissions, and levelized cost under different scenarios. A parametric study was then used to examine the sensitivity to electrolyzer efficiency, renewable penetration, and specific energy consumption. The findings provide guidance for policy, investment, and planning decisions in advancing green hydrogen toward cost-competitive and climate-effective deployment.

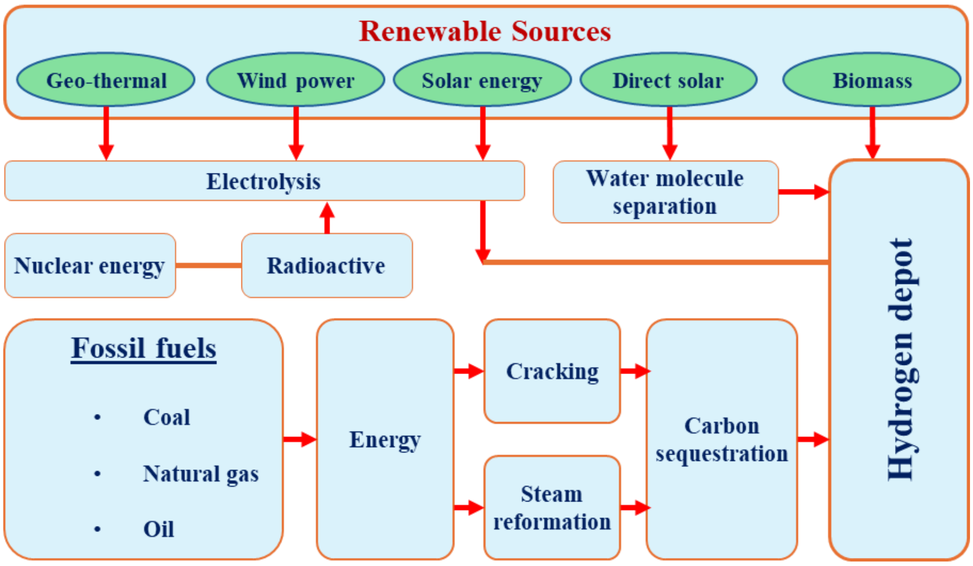

Figure 1. Production path for hydrogen.

II. Methods

The simulation framework was formulated to provide a consistent basis for analyzing how variations in renewable supply, equipment performance, and financial assumptions propagate through to hydrogen yield, avoided emissions, and the proxy levelized cost of hydrogen (LCOH). This workflow ensures that technical, environmental, and economic outcomes are consistently evaluated under variable renewable inputs, operational constraints, and financial scenarios. Figure 2 shows the flow chart for the framework used in this study.

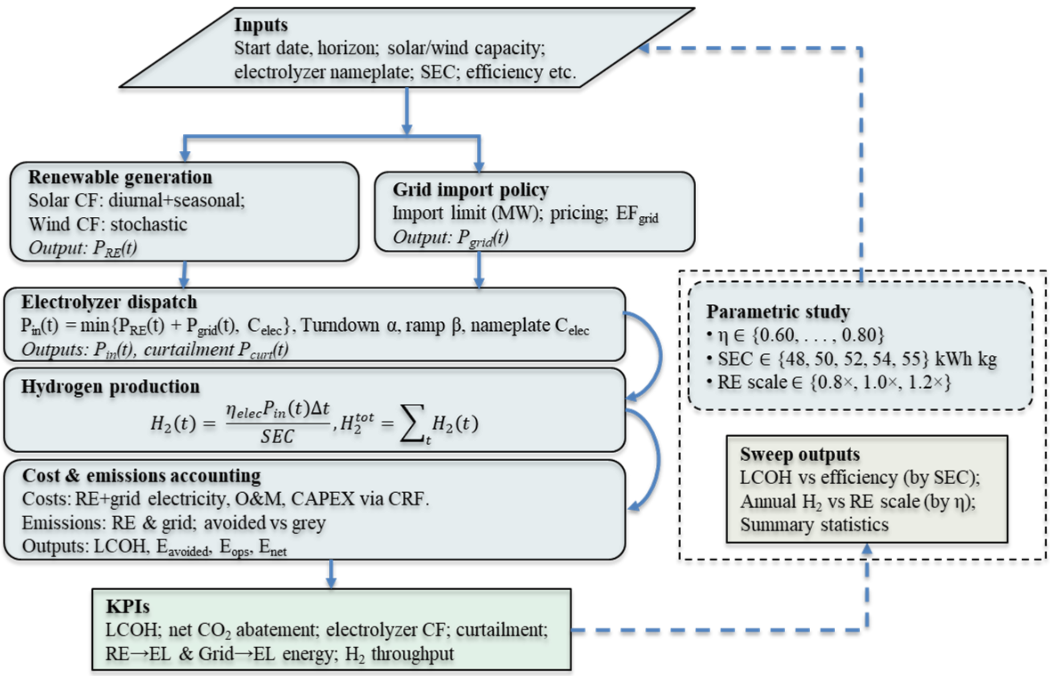

Figure 2, Flow chart for the framework used in this study.

2.1 Renewable generation model

The renewable module represents the temporal availability of wind and solar power using stylized but representative capacity factor profiles. This ensures that diurnal, seasonal, and stochastic variability are captured in a form suitable for system-level analysis. The total renewable electricity available at any hour t is modeled as the sum of solar and wind contributions:

$$P_{\mathrm{RE}}(t) = P_{\mathrm{solar}}(t) + P_{\mathrm{wind}}(t)$$

with each component expressed as

$$P_{\mathrm{solar}}(t) = C_{\mathrm{solar}} \cdot f_{\mathrm{solar}}(t), P_{\mathrm{wind}}(t) = C_{\mathrm{wind}} \cdot f_{\mathrm{wind}}(t)$$

where C is the installed capacity (MW) and $f(t)$ the capacity factor, normalized between 0 and 1. Capacity factor profiles incorporate diurnal cycles for solar and stochastic variability for wind, consistent with renewable energy system modeling practices (NREL, 2020; IEA, 2019). Outputs from this module provide the hourly renewable electricity supply available to the electrolyzer module.

2.2 Electrolyzer dispatch

The electrolyzer module translates electricity availability into hydrogen production while considering physical and operational constraints. The usable power input is limited by renewable availability, grid imports, and the electrolyzer's nameplate capacity:

$$P_{in}(t) = min\left(P_{RE}(t) + P_{grid}(t), C_{elec}\right)$$

where $\mathrm{C_{elec}}$ is the electrolyzer capacity (MW).

To reflect real operating conditions, the model imposes (i) a turndown ratio α representing the minimum stable load (typically 10–20% of rated capacity) and (ii) a ramp rate β that limits hourly changes:

$$P_{\mathrm{in}}(t) \geq \alpha \cdot C_{\mathrm{elec}} , |P_{\mathrm{in}}(t) - P_{\mathrm{in}}(t-1)| \leq \beta \cdot C_{\mathrm{elec}}.$$

Excess renewable power beyond usable input is curtailed:

$$P_{\mathrm{curt}}(t) = P_{\mathrm{RE}}(t) - \left(P_{\mathrm{in}}(t) - P_{\mathrm{grid}}(t)\right)$$

These constraints reflect empirical data on PEM and alkaline electrolyzers, which experience efficiency penalties and degradation risks if operated outside recommended ranges (IRENA, 2020; DOE, 2020). The hourly dispatch trajectory generated here is passed to the hydrogen production module.

2.3 Hydrogen production

Hydrogen yield is proportional to the input electricity, adjusted by electrolyzer efficiency (η_elec) and the specific energy consumption (SEC):

$$H_2(t) = \frac{\eta_{\mathrm{elec}} \cdot P_{\mathrm{in}}(t) \cdot \Delta t}{SEC}$$

where Δt is the simulation timestep (1 h) and SEC is measured in kWh per kg H_2. Practical SEC values for commercial electrolyzers are 48–55 kWh/kg H_2, with efficiencies typically between 60–80% (Zeng and Zhang, 2010; Saba et al., 2018; IRENA, 2020). This formulation derives from Faraday's law of electrolysis, corrected for thermodynamic and mechanical losses in real systems.

Total hydrogen production is:

$$H_2^{\mathrm{tot}} = \sum_t H_2(t)$$

This quantity forms the basis for emissions and cost calculations in the final module.

2.4 Emissions accounting

The climate benefits of green hydrogen arise from avoided emissions relative to grey hydrogen production. Avoided emissions are:

$$E_{\mathrm{avoided}} = H_2^{\mathrm{tot}} \cdot EF_{\mathrm{grey}}$$

where EF_{grey} is the emission factor of grey hydrogen, around 9–10 kgCO_2/kg H_2 (IEA, 2019).

Electricity-related emissions are:

$$E_{\mathrm{ops}} = \sum_t \left(P_{\mathrm{RE}}(t) \cdot EF_{\mathrm{RE}} + P_{\mathrm{grid}}(t) \cdot EF_{\mathrm{grid}}\right)\Delta t$$

where EF_{RE} and EF_{grid} are the carbon intensities of renewable and grid electricity, respectively.

The net emission reduction is:

$$E_{\text{net}} = E_{\text{avoided}} - E_{\text{ops}}$$

This approach mirrors lifecycle carbon accounting applied in major hydrogen system studies (IRENA, 2020; Staffell et al., 2019) and links directly to the cost module.

2.5 Cost model

To assess economic competitiveness, a proxy levelized cost of hydrogen (LCOH) is calculated. Annualized capital expenditure (CAPEX) was determined using the capital recovery factor (CRF):

$$CRF = \frac{r(1+r)^n}{(1+r)^n - 1}$$

where *r* is the discount rate and *n* is the lifetime of the project in years.

Annual CAPEX is:

$$CAPEX_{\text{ann}} = CAPEX_{\text{tot}} \cdot CRF$$

and the total annualized cost is:

$$C_{\text{tot}} = CAPEX_{\text{ann}} + OPEX$$

Finally, the proxy levelized cost of hydrogen is:

$$LCOH = \frac{C_{\text{tot}}}{H_2^{\text{tot}}}$$

This formulation is consistent with hydrogen cost assessments in Glenk and Reichelstein (2019) and IRENA (2020). The resulting metric allows direct comparison across technical, environmental, and financial scenarios.

III. Baseline Simulation

The baseline case provides a reference configuration against which parametric variations can be evaluated. It represents an urban-scale hydrogen system with a 100 MW electrolyzer supplied by a mixed portfolio of solar and wind generation, supplemented by limited grid imports. As shown in Table 1, the system was modeled over a multi-year horizon to capture both diurnal and seasonal variability, with specific energy consumption (SEC) set to 52 kWh/kg H_2 and electrolyzer efficiency initialized at representative mid-range values reported in recent techno-economic assessments (Zeng and Zhang, 2010; Saba et al., 2018; IRENA, 2020). This configuration reflects a plausible deployment scenario for the late 2020s in regions with strong renewable resources and moderate grid carbon intensity, serving as a benchmark for hydrogen yield, capacity factor, costs, and net CO_2 abatement before exploring the impacts of efficiency gains, renewable overbuild, and cost declines in future scenarios.

Table 1. Baseline simulation parameters and notes.

Parameter	Value	Notes
Start date	2024-01-01	-
Horizon	228,000 h (≈ 26 y)	Planning window for UN goals
Electrolyzer capacity	100 MW	Scale of emerging projects
Solar capacity	150 MW	Oversizing to test curtailment
Wind capacity	80 MW	Resource complementarity
SEC	52 kWh/kg	Zeng and Zhang (2010); Saba et al. (2018)
Min turndown	0.10	Typical PEM stable load (IRENA, 2020)
Ramp limit	50 MW/h	-
Grid import cap	40 MW	Partial grid support
Grid carbon intensity	0.35 kg/kWh	-
RE carbon intensity	0.02 kg/kWh	Lifecycle wind/solar
Grey H_2 EF	9.0 kg/kg H_2	SMR benchmark (IEA, 2019)
Grid power cost	$60/MWh	OECD wholesale
RE power cost	$25/MWh	LCOE of new wind/solar
Electrolyzer CAPEX	$800/kW	2024 cost estimate
Fixed O&M	$40/kW·y	Typical factor
Plant lifetime	10 y	Conservative for CRF
Discount rate	8%	-

Figure 3a shows the power balance during the first simulated week, illustrating the variability of renewable supply relative to electrolyzer demand. Renewable energy output was derived from synthetic solar and wind capacity factor profiles that incorporate seasonal and diurnal cycles, while the electrolyzer load reflects operational constraints such as minimum turndown and ramp limits. The gap between renewable generation and load highlights the role of grid imports and curtailment in sustaining near-continuous operation. This short-term view emphasizes the challenge of matching variable renewable energy to steady hydrogen production, a dynamic that scales over the full multi-year horizon.

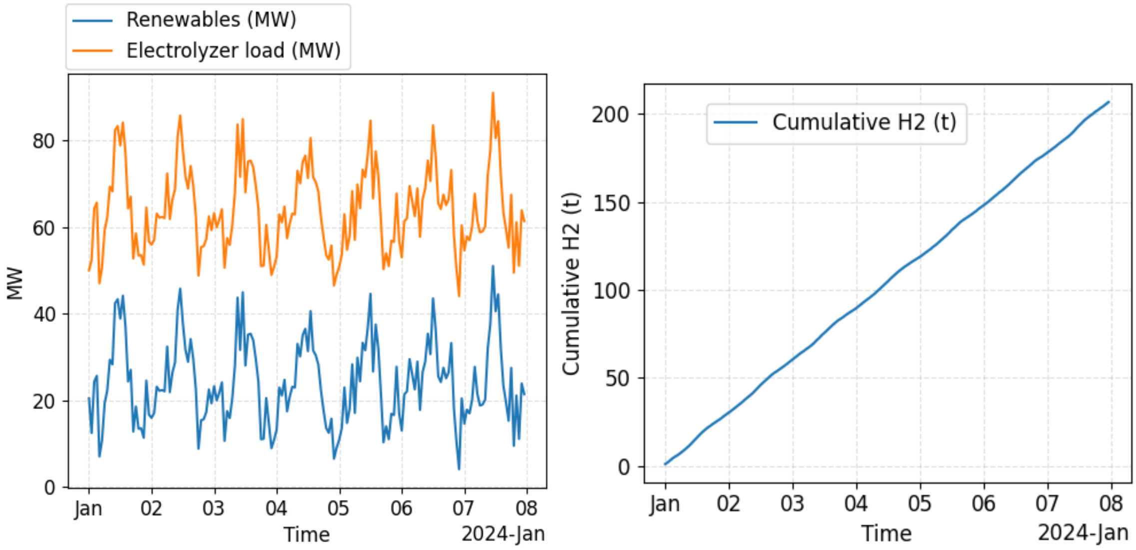

Figure 3. Simulation results for one week: (a) Electrolyzer load and renewables load over time. (b) Cumulative hydrogen produced over time.

Figure 3b presents cumulative hydrogen production over the same first-week period. The curve increases nearly linearly, reflecting sustained electrolyzer operation enabled by grid imports and partial renewable matching. Minor deviations from perfect linearity correspond to fluctuations in renewable availability and ramping behavior, but overall production remains consistent, exceeding 200 t in just one week of operation. This result demonstrates that even under variable renewable input, the system is capable of maintaining steady hydrogen output, which is critical for planning urban-scale or industrial applications.

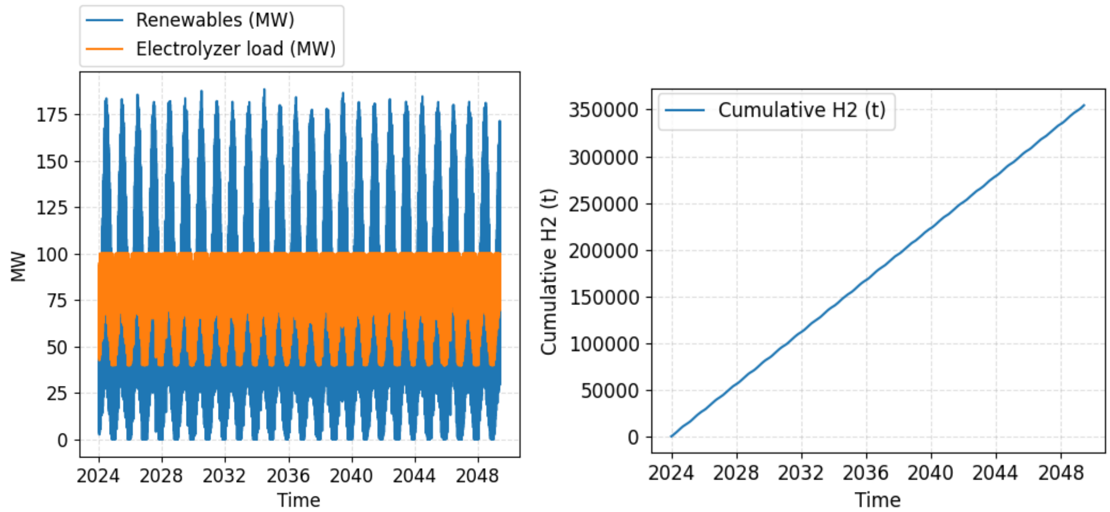

Figure 4. Simulation results to 2050 (UN goal): (a) Electrolyzer load and renewables load over time. (b) Cumulative hydrogen produced over time.

Figure 4a shows the full-horizon power balance over the 26-year simulation window. The plot highlights the strong seasonality of renewable generation, with clear annual cycles in solar availability, complemented by stochastic wind variation. The electrolyzer load tracks close to its nameplate limit for most of the horizon, supported by grid imports when renewable output is insufficient. The apparent periodicity illustrates the long-term interplay between resource seasonality and dispatch constraints, showing the value of renewable overbuild to minimize curtailment and reduce reliance on the grid.

Figure 4b presents cumulative hydrogen output across the entire 26-year horizon. The trajectory is highly linear, reflecting the stable long-term utilization of the electrolyzer stack at an average capacity factor of approximately 0.83. Over the full period, the system produces nearly 350,000 t of hydrogen, consistent with expectations from the baseline inputs. This result demonstrates that under favorable renewable and cost assumptions, long-run system behavior is predictable and scales directly with installed capacity, which is critical for evaluating contributions to 2050 net-zero hydrogen demand targets.

Table 2 summarizes outcomes from the 26-year baseline case. The system achieved a high electrolyzer capacity factor of 0.83, producing about 350,000 t of hydrogen. Renewable generation supplied the majority of the load, but nearly 7 TWh of grid electricity was also used, reflecting the reliance on external imports to maintain utilization. Curtailment was limited to around 1 TWh, indicating relatively efficient integration of renewables. Over the full horizon, green hydrogen substitution avoided more than 3.2 Mt of CO_2 compared with grey hydrogen, while electricity use contributed about 2.7 Mt of emissions, yielding a net abatement of roughly 0.52 Mt. The proxy LCOH of $2.04/kg places the system within the competitive range projected for the late 2020s, highlighting the viability of combined renewable–grid hydrogen supply under favorable resource and cost assumptions.

Table 2. Aggregated baseline outcomes (26-year projection).

Metric	Value
Electrolyzer capacity factor	0.8276
Hydrogen produced	350,000.00 t
RE → electrolyzer	11,457,678.00 MWh
Grid → electrolyzer	6,978,130.00 MWh
RE curtailment	1,067,051.00 MWh
CO_2 avoided vs. grey	3,190,813.00 t
Electricity emissions	2,671,500.00 t
Net CO_2 abatement	519,314.00 t
Proxy LCOH	$2.04/kg

IV. Parametric study

The parametric study systematically varied electrolyzer efficiency, specific energy consumption (SEC), and renewable capacity scaling to capture the range of techno-economic and environmental outcomes achievable under different system configurations. The objective is to map sensitivities that matter for planning: stack performance versus energy intensity, and the balance between electrolyzer capacity and renewable overbuild needed to sustain high utilization (IRENA, 2020; Staffell et al., 2019). Table 3 lists the explored ranges. Grid carbon intensity was kept as 350 kg/MWh.

Table 3. Parameter ranges used for the parametric study.

Parameter	Values	Rationale
Electrolyzer efficiency η	0.60, 0.65, 0.70, 0.75, 0.80	Typical range (DOE, 2020)
SEC (kWh/kg)	48, 50, 52, 54, 55	Saba et al. (2018)
RE capacity scale (×)	0.8, 1.0, 1.2	-

Across the full sweep, the levelized cost of hydrogen (LCOH) ranged from a minimum of $2.24/kg to a maximum of $3.79/kg, with an ensemble mean of approximately $2.94/kg. Annual hydrogen production over the simulation horizon spanned from 160,757 t to 274,967 t, averaging 212,163 t. Importantly, net CO_2 abatement was consistently positive, with reductions between 0.44 and 3.22 Mt relative to grey hydrogen, and a central estimate of about 1.84 Mt. These ranges illustrate both the sensitivity of outcomes to technical assumptions and the scale of opportunity for green hydrogen to contribute to decarbonization pathways.

The parametric analysis of electrolyzer efficiency and specific energy consumption (SEC) highlights the strong sensitivity of the normalized cost of hydrogen (LCOH) to these two technical parameters. As shown in Figure 5, increasing efficiency from 0.60 to 0.80 reduces LCOH by nearly 25–30% across all SEC values, showing the importance of improving conversion efficiency in lowering production costs. Similarly, reducing SEC from 55 to 48 kWh/kg H_2 yields a parallel downward shift in the cost curves, reflecting incremental gains in system performance.

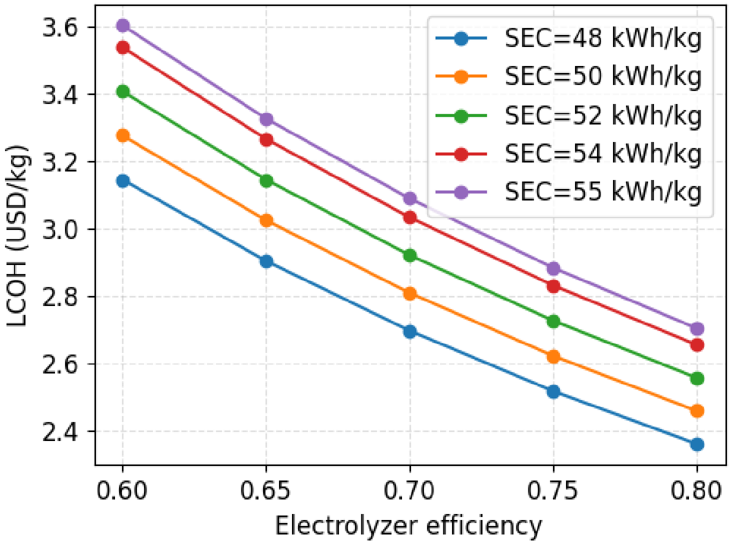

Figure 5. Parametric study results: LCOH vs. electrolyzer efficiency grouped by SEC.

The near-linear decline across the studied range indicates that cost reductions are highly sensitive to simultaneous improvements in both efficiency and SEC. These results confirm findings in previous techno-economic assessments that electrolyzer technology advancement remains the single most influential lever for achieving cost-competitive green hydrogen production (Saba et al., 2018; Glenk and Reichelstein, 2019; IRENA, 2020).

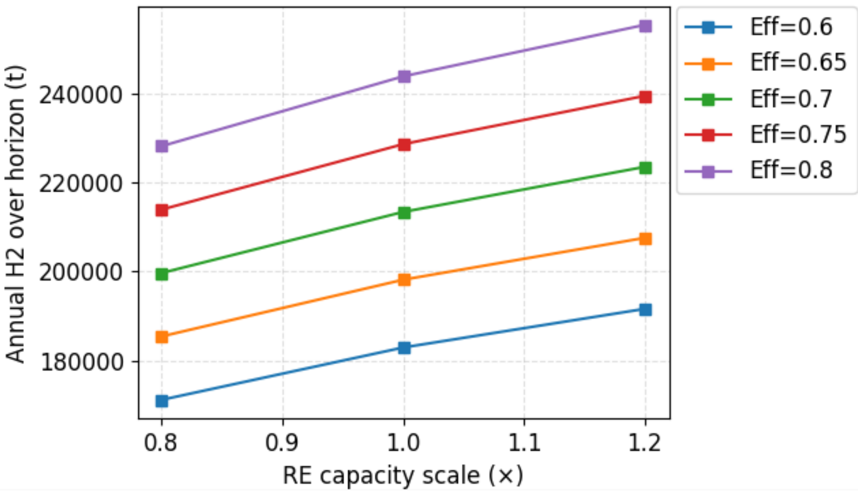

Figure 6. Parametric study results: Annual hydrogen over the horizon vs. renewable scale, grouped by efficiency.

Similarly, the parametric analysis of the scaling of renewable capacity and electrolyzer efficiency demonstrates the strong influence of both factors on total hydrogen production. As shown in Figure 6, increasing the renewable capacity scale from 0.8× to 1.2× results in a nearly proportional increase in hydrogen output across all efficiency levels, reflecting the direct dependence of production on electricity availability. At the same time, higher electrolyzer efficiencies (from 0.60 to 0.80) yield significant upward shifts in the production curves, with efficiency gains amplifying the benefits of larger renewable installations. The combined effect highlights the importance of coordinated improvements in both renewable supply and electrolyzer performance to maximize green hydrogen yield in future energy systems.

4.1 Discussion and practical implications

The baseline multi-year run shows that an urban-scale system can achieve high utilization ($CF \approx 0.83$) and positive net abatement at about \$2.0/kg H_2 under favorable RE costs and a mid-carbon grid. This aligns with techno-economic expectations for the late 2020s in strong-resource regions (IRENA, 2020; Glenk and Reichelstein, 2019). Looking to 2050, most net-zero pathways anticipate much lower grid carbon intensity, cheaper renewables, and improved electrolyzer performance (IEA, 2019; Staffell et al., 2019). Hence, LCOH falls further and net abatement increases.

From a practical perspective, the sensitivity of LCOH to electrolyzer efficiency and SEC has direct implications for scaling up green hydrogen under 2030–2050 UN goals. A reduction of LCOH by 25–30% through efficiency gains corresponds to absolute cost savings of nearly \$0.8–1.0/kg H_2, which can decisively shift green hydrogen towards economic parity with grey hydrogen in key markets. Such cost reductions are particularly significant in industrial sectors like steel making and fertilizer production, where hydrogen demand is projected to expand rapidly (IEA, 2019; Staffell et al., 2019). By 2050, when annual global demand could exceed 600 Mt H_2 (IEA, 2019; IRENA, 2020), efficiency-driven savings at scale could represent several hundred billion dollars in avoided energy expenditures, while simultaneously reducing life-cycle emissions. These findings emphasize that investments in electrolyzer R&D and large-scale deployment incentives are not only technologically critical but also economically indispensable to achieve net-zero energy system transitions.

Renewable scaling, when combined with electrolyzer efficiency improvements, also reshapes hydrogen system planning in pursuit of net-zero 2050 goals. A 20% increase in renewable capacity translates into additional production on the order of 30–40 kt H_2/yr for the system size studied, corresponding to hundreds of millions of cubic meters of hydrogen available for industrial and mobility applications. When paired with an efficiency improvement from 0.60 to 0.80, production potential increases by more than 60 kt H_2/yr, effectively lowering average costs by spreading fixed expenditures over a larger output base. Such scaling effects are consistent with global roadmaps (IEA, 2019; IRENA, 2020) that emphasize simultaneous expansion of renewable portfolios and electrolyzer learning curves as critical enablers of cost-competitive green hydrogen by mid-century. The findings therefore reinforce the case for integrated investment strategies that couple renewables deployment with rapid electrolyzer performance gains to achieve the net-zero 2050 goals.

Taken together, these results show that the pathway to competitive and climate-effective green hydrogen rests on two parallel combination of factors: sustained improvements in electrolyzer efficiency and aggressive scaling of renewable electricity supply. Efficiency gains directly reduce the unit cost of hydrogen, while renewable expansion ensures sufficient volumes to displace fossil-derived hydrogen at scale. The combination positions green hydrogen as both an economically viable and environmentally indispensable energy vector, reinforcing its central role in meeting UN mid-century net-zero goals.

V. Conclusion

The objective of this work was to develop and illustrate a framework that couples renewable variability, electrolyzer operations, and cost and emissions accounting to simulate systems behavior at weekly operational timescale as well as projected timescales reflecting UN 2050 net-zero goals. A parametric study was also conducted to identify levers that improve cost and climate performance toward 2050 objectives. The results have been presented with the following key findings:

- with a 100 MW electrolyzer and mixed 150/80 MW solar/wind supply, the system achieved \$2/kg proxy LCOH, and 0.45 Mt CO_2 net abatement over 26 years at a grid EF of 350 kg/MWh.
- The first week view validated dispatch under ramp/turndown limits and highlighted curtailment windows while the 26-year view maintained the same trends for mid-century outcomes.
- Electrolyzer efficiency and SEC dominated LCOH; moving from $\eta = 0.60$ to 0.80 typically reduces cost by ≈\$1/kg, consistent across SEC bands.
- Up-sizing renewables raised hydrogen output but with diminishing returns beyond ≈1.0× because curtailment grows unless storage or additional flexibility is added.
- The net abatement turned negative at high grid EF. Clean PPAs or temporally matched renewables are decisive for net-zero alignment.
- For near-term deployments, clean electricity contracting and gradual efficiency improvements should be prioritized before substantial overbuilding of renewables.

In conclusion, as grids decarbonize toward 2050, the same electrolyzer assets are expected to deliver greater net abatement at stable or declining costs, provided that procurement strategies secure low-carbon electricity. For future projections, coupling electrolysis with storage, thermal co-utilization, and realistic degradation models will further enhance techno-economic fidelity and reduce investment risk, thereby strengthening the return on investments of large-scale projects. Ultimately, this study demonstrated that deliberate project development aligned with international climate roadmaps (such as the UN 2050 Agenda and mid-century net-zero commitments) will accelerate the transition to cost-competitive green hydrogen, a cornerstone technology for decarbonizing heavy industry and transport.

VI. Data Availability Statement

All data, models, or codes used/developed in the course of this study are available from the corresponding author(s) upon reasonable request.

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