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Original Research Article

Hydrogen Mobility Technologies for Emerging Markets: A Dual-Readiness, Techno-Economic and Well-to-Wheel Assessment with a Türkiye Case Study

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Abstract: Hydrogen is widely proposed for the freight and heavy-duty segments that resist direct electrification, but the supporting evidence has been developed largely for high-income markets and is split across separate literatures on technology readiness, production cost and vehicle economics, none of which answers the question facing an emerging-market decision-maker: whether a given hydrogen technology is at once deployable, affordable and clean in that country. This study answers the question end to end for Türkiye, by separating global technology maturity from an emerging-market readiness level scored against local manufacturing, infrastructure, regulation, workforce and supply chain, and by joining that readiness assessment to a single cost and emissions chain running from the electrolyzer to the dispenser nozzle and on to the vehicle. Readiness transfers unevenly: the gap between the global frontier and what Türkiye can currently build, staff and regulate is about two levels for hydrogen engines and large-scale alkaline electrolysis, but four to six levels for fuel cell vehicles, high-pressure storage and stack manufacturing. Renewable hydrogen can be produced for roughly 4 USD/kg at the plant gate yet reaches a captive fleet at nearly twice that figure, and at such a delivered price no hydrogen truck competes with diesel. The electricity source, rather than the powertrain, governs the climate outcome: hydrogen produced from the current Turkish grid carries well-to-wheel emissions two to two and a half times those of diesel, whereas dedicated renewable supply cuts them by about 70%. Hydrogen is therefore not a single proposition. Renewable-coupled alkaline electrolysis is supported by cost, emissions and industrial feasibility alike; battery electrification is the near-term answer for road freight; and hydrogen engines are justified by deployability rather than economics, within defined transitional niches. Readiness, cost and emissions must therefore be assessed together, since each alone points to a different technology.

Keywords: fuel cell electric vehicles; hydrogen internal combustion engine; levelized cost of hydrogen; total cost of ownership; water electrolysis; well-to-wheel assessment; technology readiness.

1. Introduction

1.1. Context

The global transportation sector accounts for approximately 23% of energy-related CO₂ emissions, equivalent to about 7.3 Gt CO₂ annually [1]. Hydrogen has emerged as a candidate energy carrier for the segments that resist direct electrification, offering zero tailpipe CO₂, a gravimetric energy density of 120 MJ/kg (roughly three times that of gasoline), and compatibility with variable renewable generation [2]. Global hydrogen vehicle deployment was projected to increase from approximately 50,000 units in 2020 to over 18 million by 2050, a compound annual growth rate exceeding 35% [2,3], although such projections have been revised downwards repeatedly as fuel-cell vehicle sales have fallen short and refueling networks have contracted rather than expanded in several jurisdictions [4].

Leading economies have embedded hydrogen in their long-term strategies. The European Union's Hydrogen Strategy targets at least 40 GW of electrolyzer capacity by 2030 [3], and Japan's Basic Hydrogen Strategy envisages 800,000 fuel cell vehicles by 2030 [5]. Türkiye's Hydrogen Technologies Strategy and Roadmap sets electrolyzer targets of 2 GW by 2030, 5 GW by 2035 and 70 GW by 2053, aligned with the national 2053 net-zero commitment [6]. For emerging markets more generally, the transition presents a distinctive combination of opportunity and constraint: technology costs continue to decline along established learning curves [7], but the enabling manufacturing base, refueling infrastructure, regulatory apparatus and specialized workforce that make those costs realizable are frequently absent [8,9].

1.2. What the Existing Literature does and does not Provide

Three strands of literature bear on the question addressed here, and each leaves a specific gap.

The first strand reports technology maturity using the nine-level TRL scale [10]. These assessments are almost invariably single-valued and globally referenced. A global TRL of 9 for alkaline electrolysis is an accurate statement about the international frontier and a misleading one about what a Turkish, Indian or Brazilian project developer can procure, permit, staff and maintain domestically. The TRL scale was designed to describe the maturity of a technology, not the absorptive capacity of a receiving system, and applying it unmodified to an emerging-market context conflates the two.

The second strand comprises country- or region-specific techno-economic assessments of green hydrogen, including recent Turkish studies reporting plant-gate costs of roughly 2.0–7.0 USD/kg depending on resource, site and electrolyzer technology [11,12]. These studies are typically confined to the production step. They stop at the plant fence, so the price a fleet operator pays is not derived; and they rarely propagate the production cost into a vehicle-level cost or emissions comparison, so they cannot say whether the hydrogen produced would displace diesel.

The third strand comprises vehicle-level TCO and life-cycle comparisons of diesel, battery and fuel-cell heavy-duty powertrains [13–16]. These are methodologically mature but are

overwhelmingly parameterized by high-income markets with low-carbon grids, cheap capital and dense charging or refueling networks. Their conclusions do not transfer: a discount rate of 4% and a grid carbon intensity of 0.15 kg CO₂/kWh produce a different technology ranking from 10% and 0.42 kg CO₂/kWh.

No study known to the author closes the loop between the three strands. Readiness literature does not price its conclusions; production-cost literature does not reach the vehicle; the vehicle literature does not question whether the technology it costs is procurable in the country it describes.

1.3. Contribution and Novelty

The contribution of this work is the integration of these three strands into a single, internally consistent and reproducible decision chain, applied end-to-end to one emerging market. Specifically:

- 1. A dual-readiness construct with an explicit scoring rule.** Rather than asserting a second TRL by judgment, an Emerging-Market Readiness Index is defined over five anchored criteria with published weights, aggregated by a stated formula, capped by the global TRL, and tested against a Dirichlet perturbation of the weight vector (Section 2.3). The output is a transfer gap with an uncertainty interval, not a point assertion.
- 2. A cost chain that runs from the electrolyzer rectifier to the dispenser nozzle.** Plant-gate LCOH and delivered pump price are computed separately and explicitly bridged by a component-level delivery build-up for two distinct configurations, a captive depot and a public retail station (Sections 2.4, 2.5 and 8.2). The delivered price used in the vehicle comparison is therefore derived rather than assumed.
- 3. A dispatch model with real electrolyzer constraints.** Minimum load, part-load specific consumption, hot standby, cold-start production loss and curtailment are represented explicitly, and the renewable oversizing ratio is optimized against the resulting LCOH (Sections 2.6 and 8.3).
- 4. A transport-service-equivalent vehicle comparison.** Powertrains differ in tare mass and therefore in payload. Costs and emissions are reported per payload ton-kilometer in addition to per vehicle-kilometer, which changes the ranking of the battery electric option (Sections 2.7 and 8.5).
- 5. An uncertainty treatment that admits parameter dependence and tests its own method.** Input distributions are rank correlated rather than independent, which is shown to widen the cost distribution by about 12%. Sensitivity is quantified by variance-based Sobol indices alongside the conventional one-at-a-time tornado, and the two are compared rather than one being assumed superior: over the ranges relevant here the model turns out to be close to additive, so the tornado ranking is confirmed rather than overturned (Sections 2.9 and 8.7).
- 6. A reconciliation rather than a corroboration.** The screening, dispatch and stochastic estimates of LCOH are shown to differ because of stated boundary differences, and the differences are decomposed step by step (Section 8.4).

Table 1 positions this study against representative prior work. The comparison is restricted to the dimensions this paper claims to advance; it is not a quality ranking.

Table 1. Position of this study relative to representative prior assessments.

Feature	Global TRL Reviews [8,10,17]	Türkiye LCOH Studies [11,12]	HDV TCO/LCA Studies [13–16]	This Study
Readiness assessed	Single global TRL	Not assessed	Not assessed	Global TRL and scored EMRI with weight sensitivity
Production cost boundary	—	Plant gate	Delivered price assumed	Plant gate and derived delivered price
Temporal resolution of supply	—	Annual average	—	8,760 h with electrolyzer constraints
Vehicle comparison	—	—	Per vehicle-km	Per vehicle-km and per payload t-km
Emissions boundary	—	Production only	Cradle-to-grave or WTW	WTW with stated exclusions and H ₂ leakage GWP
Uncertainty	Qualitative	Deterministic or OAT	Scenario-based	Rank-correlated Monte-Carlo + Sobol indices
Geographic claim	Global	Türkiye, production only	High-income markets	Türkiye, with explicit cross-country positioning

1.4. Scope limitation

Türkiye is treated here as a case study, not as a proxy for emerging markets in general. Section 7.4 compares Türkiye's industrial base, electricity mix, financing conditions, hydrogen policy and freight structure with those of five other emerging economies and identifies which of the conclusions are portable and which are not. Conclusions stated without that qualification apply to Türkiye alone.

2. Materials and Methods

2.1. Article Type, Scope and Reporting

This is an original research article. It develops and applies quantitative models; the literature review it contains serves to parameterize and bound those models rather than to constitute the contribution in itself. It is therefore not a systematic review in the PRISMA sense, and no claim of exhaustive coverage or formal risk-of-bias assessment is made. It does, however, follow a documented and reproducible selection protocol (Section 2.2) so that the provenance of every model input can be traced, and it reports the protocol using a PRISMA-style flow diagram for transparency. Readers seeking a comprehensive synthesis of the hydrogen mobility literature should consult the dedicated reviews cited throughout Sections 3–6.

All monetary values are in 2025 USD. Units follow SI conventions throughout: kg/m³, A/cm², kWh/kg, km/yr, g CO₂eq/km, USD/kg. Hydrogen is written H₂ and carbon dioxide equivalent CO₂eq without exception. Symbols are defined in the Nomenclature.

2.2. Evidence Base: Search and Selection Protocol

Three categories of source were consulted: peer-reviewed journal articles, international standards and regulations, and institutional energy and market reports.

1. **Databases and search window.** Scopus, Web of Science and ScienceDirect were searched over the window 2007–2025, with institutional data restricted to 2023–2025 to avoid stale market figures. The final search was executed on 30 April 2025.
2. **Search strings.** The Boolean core was (“hydrogen” AND (“fuel cell” OR “internal combustion” OR “electrolysis” OR “storage” OR “refuel”)) AND (“vehicle” OR “truck” OR “bus” OR “mobility” OR “heavy-duty”) AND (“levelized cost” OR “total cost of ownership” OR “life cycle” OR “technology readiness” OR “efficiency” OR “durability”). For country-specific searches, (“Türkiye” OR “Turkey”) was substituted for the third clause.
3. **Inclusion criteria.** (a) reports at least one quantitative performance, cost or emission parameter usable as a model input or benchmark; (b) states its own system boundary and reference year; (c) peer-reviewed or issued by an institution with a published methodology; (d) English-language full text available.
4. **Exclusion criteria.** (a) outside hydrogen mobility; (b) no extractable quantitative parameter; (c) conference abstract without full text; (d) superseded by a more recent publication from the same group covering the same system; (e) below the quality threshold of Table 2.
5. **Quality appraisal.** Each full-text candidate was scored against the five criteria of Table 2. Sources scoring fewer than 3 of 5 criteria were excluded; sources scoring 3 were retained only as corroborating rather than primary parameter sources.
6. **Outcome.** The selection process is summarized in Figure 1. Of 1,451 records identified, 918 remained after duplicate removal, 214 were assessed in full text, and 71 sources were retained (46 peer-reviewed journal articles, 19 institutional and technical reports and 6 standards or regulatory documents), of which 61 are cited. The distribution of the retained peer-reviewed sources by topic and publication period is given in Table 3.

Table 2. Quality-appraisal criteria applied to full-text candidates.

Criterion	Requirement for a Positive Score
Boundary transparency	System boundary and functional unit explicitly stated
Parameter traceability	Input values sourced, not asserted
Reference year	Cost or emission year stated and after 2015 (technology data) or 2022 (market data)
Reproducibility	Method described in sufficient detail to be re-implemented
Independence	Funding and conflicts declared, or institutional source with published methodology

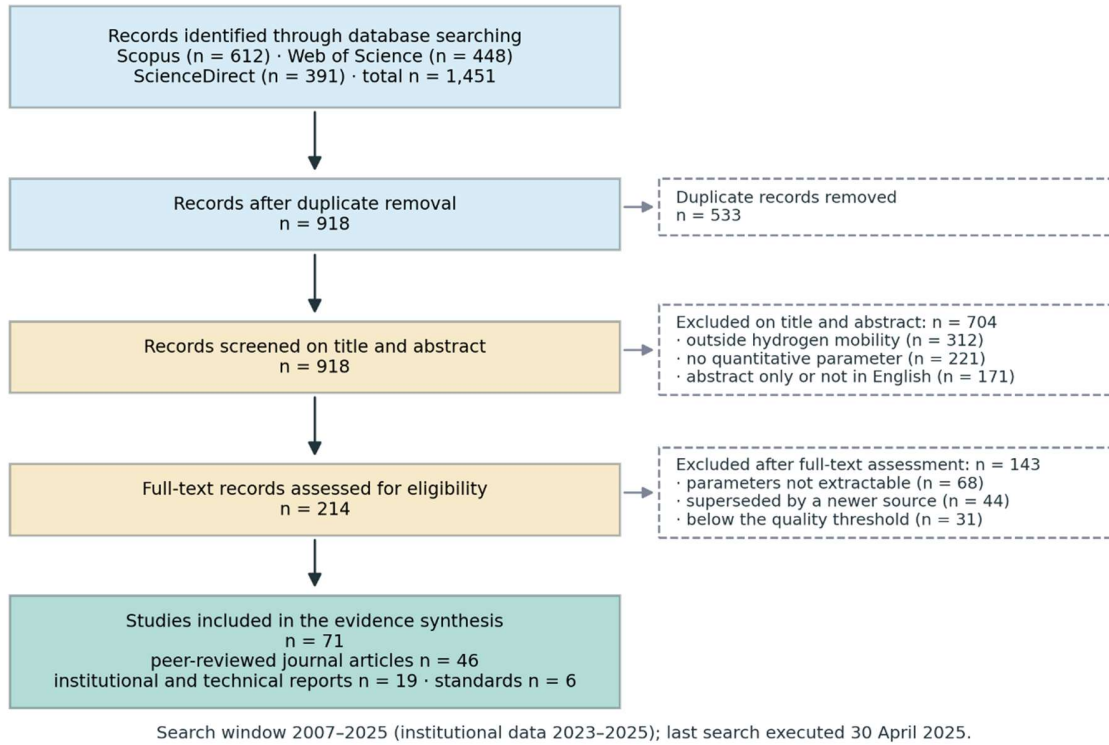


Figure 1. Identification, screening and selection of the evidence base. Counts refer to the search executed on 30 April 2025 over Scopus, Web of Science and ScienceDirect.

Table 3. Distribution of the retained peer-reviewed journal articles by topic and publication period.

Topic	2007–2015	2016–2020	2021–2025	Total
Fuel cell technology and durability	2	3	3	8
Hydrogen internal combustion engines	2	2	3	7
On-board hydrogen storage	2	3	2	7
Water electrolysis and dynamic operation	2	3	3	8
Techno-economics, LCOH and TCO	0	1	6	7
Life-cycle and well-to-wheel emissions	1	1	3	5
Safety, acceptance and infrastructure	0	1	3	4
Total	9	14	23	46

2.3. Dual-Readiness Framework

2.3.1. Rationale for Departing from a Single TRL

Conventional TRL measures the maturity of a technology in the hands of those who developed it [10]. What limits deployment in an emerging market is a different quantity: whether the receiving economy can manufacture, install, regulate, staff and supply the technology. These are distinct constructs and mapping the second onto the nine-level TRL scale without justification is a category error. Two responses are possible: adopt a separate readiness taxonomy, or define an explicit, auditable mapping. The second option is taken here because it preserves comparability with the large body of literature that reports TRL, while making the mapping falsifiable.

2.3.2. The Emerging-Market Readiness Index

Five criteria are scored on a 1–9 scale with the anchor descriptors of Table 4: local manufacturing capability (s_1), enabling infrastructure (s_2), regulatory and standards maturity (s_3), workforce and skills (s_4), and supply-chain independence (s_5). The index is the weighted sum of Equation (1),

$$EMRI_i = \sum_{j=1}^5 w_j s_{ij}, \quad \sum_{j=1}^5 w_j = 1 \quad (1)$$

with the baseline weights $w = (0.30, 0.25, 0.15, 0.15, 0.15)$. Manufacturing capability and infrastructure carry the largest weights because they are the two criteria that cannot be established or remedied on a project timescale; regulation, workforce and supply chain are equally weighted because each is remediable within a comparable horizon given policy attention. The emerging-market readiness level and the technology-transfer gap follow from Equation (2) as

$$TRL_i^{EM} = \min(TRL_i^G, EMRI_i), \quad \Delta_i = TRL_i^G - TRL_i^{EM} \quad (2)$$

The minimum operator enforces the requirement that local readiness cannot exceed the global frontier: an economy cannot deploy a technology more maturely than it exists.

Table 4. Anchor descriptors for the five EMRI criteria. Intermediate scores are interpolated.

Criterion (Weight)	Score 1–3	Score 4–6	Score 7–9
Local manufacturing (0.30)	No domestic capability; complete import dependence	Assembly or partial localization of balance of plant; core component imported	Core component manufactured domestically at commercial scale
Enabling infrastructure (0.25)	Absent; no operating installation in country	Pilot or demonstration installations; no commercial network	Commercially operating network with routine service capability
Regulation and standards (0.15)	No national code; case-by-case permitting	National code adopted by reference to an international standard; permitting slow	Mature national code with established permitting practice and accredited inspection
Workforce and skills (0.15)	No trained personnel; expatriate dependence	Adjacent skills transferable with short conversion training	Established vocational and engineering pipeline
Supply-chain independence (0.15)	Single foreign supplier; no local content	Multiple suppliers; partial local content	Diversified supply with substantial local content

2.3.3. Robustness of the Scores

Two limitations are acknowledged rather than concealed. First, the scores in Section 7.1 are assigned by the author from the sources cited in Sections 3–7 and from Turkish industrial and regulatory data; they have not been validated by a formal multi-expert elicitation, which remains the principal methodological gap of the readiness component of this work. Second, the weight vector is a matter of judgment.

The second limitation is addressed quantitatively. The weight vector is perturbed by drawing 2,000 samples from a Dirichlet distribution centered on the baseline weights with concentration parameter 25, which admits weight variations of roughly ± 0.06 on each

criterion, and the resulting distribution of the transfer gap is reported as a 5th–95th percentile interval (Section 7.1). A gap whose interval does not overlap that of another technology is robust to any weighting within this family. The first limitation is addressed by reporting the sensitivity of each gap to a ± 1 perturbation of every individual criterion score, and by restricting the policy claims of Section 8.9 to gap orderings that survive both perturbations rather than to absolute gap magnitudes.

2.4. Plant-Gate Levelized Cost of Hydrogen

The plant-gate boundary comprises the rectifier, electrolyzer stack, balance of plant, water treatment, gas purification and drying, low-pressure buffer at 30 bar, civil works, installation, engineering and contingency. It excludes compression above 30 bar, high-pressure storage, distribution, dispensing and retail margin, all of which are treated separately in Section 2.5. This division is stated because conflating them is the single most common source of non-comparable LCOH figures in literature.

The plant-gate cost is given by Equation (3), in which the capital recovery factor of Equation (4) annualizes the installed capital:

$$LCOH_{pg} = \frac{CRF(i, N) C_{inst} + f_{OM} C_{inst} + A_{stack}}{\dot{m}_a} + SEC_{sys} P_{el} + c_m \quad (3)$$

where the capital recovery factor is

$$CRF(i, N) = \frac{i(1+i)^N}{(1+i)^N - 1} \quad (4)$$

and the installed capital cost is the equipment cost scaled by an installation, engineering and contingency factor, $C_{inst} = \kappa C_{eq}$, with $\kappa = 1.25$.

The annual hydrogen yield per unit of rated electrolyzer power follows from Equation (5):

$$\dot{m}_a = \frac{8760 CF}{SEC_{sys}} \quad (5)$$

The system specific energy consumption of Equation (6) accounts for auxiliaries and for degradation between stack replacements:

$$SEC_{sys} = SEC_{BoL} \left(1 + 1/2 \delta \frac{h_{repl}}{1000} \right) (1 + \alpha) \quad (6)$$

with δ the degradation rate per 1,000 operating hours, $h_{repl} = \min(h_{stack}, N \cdot 8760 CF)$ the operating interval between replacements, and α the auxiliary load fraction. The factor of one half converts an end-of-interval degradation into its mean over the interval, since efficiency is restored at replacement.

Stack replacement is annualized from its present value in Equation (7):

$$A_{stack} = CRF(i, N) \sum_{k=1}^{n_{repl}} \frac{\beta C_{eq}}{(1+i)^k h_{stack}/(8760 CF)}, \quad n_{repl} = \left\lceil \frac{8760 N CF}{h_{stack}} \right\rceil - 1 \quad (7)$$

where β is the stack cost as a fraction of equipment cost (0.35 for alkaline, 0.45 for PEM) and h_{stack} the stack lifetime (80,000 h and 60,000 h respectively). Water and consumables are taken as $c_m = 0.05$ USD/kg.

2.5. From Plant Gate to Dispenser: The Delivered Hydrogen Price

The delivered price of Equation (8) is the plant-gate cost plus a build-up of ten components:

$$P_{\text{del}} = \text{LCOH}_{\text{pg}} + \underbrace{c_{\text{comp}}^{\text{cap}} + c_{\text{comp}}^{\text{OM}} + c_{\text{comp}}^{\text{en}}}_{\text{compression } 30 \rightarrow 500 \text{ bar}} + c_{\text{sto}} + c_{\text{dist}} + \underbrace{c_{\text{stn}}^{\text{cap}} + c_{\text{stn}}^{\text{OM}} + c_{\text{stn}}^{\text{en}}}_{\text{dispensing station}} + c_{\text{loss}} + c_{\text{marg}} \quad (8)$$

Capital components are annualized with Equation (4) over 20 years (compression) and 15 years (station) and divided by the annual throughput, which is the product of nameplate capacity, 365 days and the availability or utilization factor. Two configurations are evaluated: a depot chain serving a captive heavy-duty fleet (1,000 kg/d compression at 85% availability, 350/700 bar depot dispenser rated 1,000 kg/d at 70% utilization, 100 km one-way tube-trailer distribution) and a public retail chain (500 kg/d dispenser at 40% utilization, longer haul). Losses are 2% (depot) and 3% (retail) of the subtotal, while margin is 6% and 10% respectively. The depot chain is the relevant one for the heavy-duty fleet application analyzed in Section 8.5; the retail chain is reported because it explains the pump prices observed in operating markets and because it bounds the light-duty case.

2.6. Hourly Renewable Dispatch with Electrolyzer Operating Constraints

2.6.1. Renewable Profiles

Hourly generation is synthesized for an inland central-Anatolian site at 38.5° N. The solar profile is built from clear-sky solar geometry modulated by an autocorrelated daily clearness index (AR(1) coefficient 0.72) and an hourly noise term. The wind profile is generated from an Ornstein–Uhlenbeck wind-speed process ($\varphi = 0.92$) with a lognormal marginal, a winter-high seasonal modulation of $\pm 18\%$, and a generic 3.6 MW power curve with cut-in 3 m/s, rated 12 m/s and cut-out 25 m/s, reduced by 4% for wake and availability losses.

2.6.2. Calibration and Its Limits

A single scaling factor for each technology, derived from a 30-year synthetic ensemble, sets the long-run mean capacity factor to the published Turkish values of 0.185 (utility PV) and 0.31 (onshore wind). Because the factor is applied once to the whole ensemble rather than per year, interannual variability is preserved: across ten synthetic years the realized capacity factors range 0.177–0.190 (solar) and 0.281–0.321 (wind), and the monthly profile reproduces the expected summer-peaking solar and winter-peaking inland wind regimes.

It must be stated plainly that this is calibration, not validation. No measured or reanalysis time series was available to the author for the site considered, and the synthetic series therefore reproduce the first- and second-order statistics of Turkish renewable generation without reproducing the actual chronology, the spatial correlation structure, or the extreme low-generation episodes that measured data would contain. The consequences are quantified in three ways: a ten-year stochastic ensemble is reported (Section 8.3), the

electrolyzer capacity factor is carried through the Monte-Carlo analysis as a distributed rather than fixed parameter (Section 2.9), and the limitation is restated in Section 10. Practitioners applying the framework should substitute site-measured or reanalysis data (PVGIS, ERA5, MERRA-2); the model accepts an arbitrary 8,760-value series in place of the synthetic one. It is also noted that the Aegean coastal wind regime, which peaks in summer, is complementary to solar in the opposite sense to the inland regime modelled here, so the hybrid benefit reported in Section 8.3 is site-specific.

2.6.3. Electrolyzer Constraints

In each hour the available renewable power g_t (in per-unit of electrolyzer rating, equal to the oversizing ratio r times the normalized hybrid generation) is offered to the electrolyzer. Operation is subject to:

- a rated-power ceiling, so that $x_t = \min(g_t, 1)$ and the excess $g_t - x_t$ is curtailed;
- a minimum load $x_{\min}$ (0.15 alkaline, 0.05 PEM), below which the stack enters hot standby drawing 1% of rated power and producing nothing;
- a part-load specific consumption given by Equation (9),

$$SEC(x) = SEC_{nom}(0.955 + 0.045x) \left(1 + \frac{\alpha}{x}\right) \quad (9)$$

which reproduces the two competing effects: ohmic losses raise consumption towards full load, while fixed auxiliary draw raises it towards minimum load;

- a cold-start penalty of 0.5 h of lost production whenever operation resumes after more than 8 consecutive hours off.

Hydrogen output is $\dot{m}_t = x_t(1 - \gamma_t) / SEC(x_t)$ per unit rated power, with γ_t the cold-start loss fraction. The plant contracts for the full renewable output under a power purchase agreement, so curtailed energy is paid for; this is the conservative and commercially realistic assumption, and it is what makes the LCOH-oversizing relationship U-shaped.

2.7. Total Cost of Ownership on an Equivalent Transport-Service Basis

The net present value of ownership over N_v years is given by Equation (10):

$$NPV = C_0 + C_{\text{infra}} + \sum_{t=1}^{N_v} \frac{(c_f + c_m + c_c)L + F_t + R_t}{(1+i)^t} - \frac{\rho C_0}{(1+i)^{N_v}} \quad (10)$$

where C_0 is the purchase price, C_{infra} the per-vehicle share of depot refueling or charging infrastructure, L the annual mileage (km/yr), c_f the fuel or energy cost per kilometer, c_m maintenance per kilometer, c_c the carbon cost per kilometer, F_t fixed annual costs (insurance, road tax, inspection), R_t scheduled component replacement in year t , and ρ the residual value fraction.

The fuel term of Equation (11) makes the unit conversion explicit, which was previously ambiguous:

$$c_f = \frac{q_{100}}{100} P_{\text{fuel}} \left[\frac{L \text{ or kWh or kg}}{100 \text{ km}} \cdot \frac{1}{100} \cdot \frac{\text{USD}}{L \text{ or kWh or kg}} = \frac{\text{USD}}{\text{km}} \right] \quad (11)$$

and the carbon term is $c_c = e_{\text{WTW}} P_{\text{CO}_2} \times 10^{-6}$ with e_{WTW} in g CO₂eq/km and P_{CO_2} in USD/t.

Results are levelized two ways through Equation (12):

$$LC_{km} = \frac{NPV \cdot CRF(i, N_p)}{L}, \quad LC_{tkm} = \frac{LC_{km}}{m_{pay}} \quad (12)$$

The second form is the one that compares powertrains under an equivalent transport-service requirement. A 40 t gross-combination diesel tractor-semitrailer carries about 26 t of payload; the battery pack of an equivalent battery electric truck adds roughly 3.5 t of tare mass, the fuel-cell system and 700 bar tanks about 1.5 t, and an H₂-ICE conversion about 1.0 t, giving payloads of 22.5, 24.5 and 25.0 t respectively even after allowing for the 2 t zero-emission-vehicle weight derogation applied in several jurisdictions. Comparing only per-vehicle-kilometer costs implicitly compares a 22.5 t transport service with a 26 t one.

Scheduled replacements are a fuel-cell stack overhaul in year 6 (32,000 USD) and a battery module replacement in year 7 (45,000 USD); the H₂-ICE requires no stack or pack replacement within the horizon but carries the highest maintenance rate (0.125 USD/km) because it retains a full mechanical valvetrain, lubrication system and after-treatment. Vehicle availability differs (0.97 diesel, 0.96 hydrogen, 0.94 battery electric) and is reported but not monetized in the baseline, since depot overnight charging absorbs most of the battery-electric downtime at the 100,000 km/yr duty considered; a sensitivity in which the availability difference is monetized as lost revenue is reported in Section 8.5. The replacement schedule and the infrastructure allocation are consistent with published component-sizing and ownership-cost analyses of fuel-cell trucks [18].

2.8. Well-to-wheel greenhouse gas assessment: boundary and exclusions

The environmental analysis of this paper is a well-to-wheel greenhouse-gas assessment, not a life-cycle assessment, and is described as such throughout. The terminology of the submitted version was inaccurate and has been corrected.

1. **Included.** Fuel or electricity production, including upstream fuel supply; transmission and distribution losses for electricity (7.8%); compression, storage and dispensing energy (4.0 kWh/kg drawn from the grid); vehicle operation; and the indirect radiative effect of hydrogen leakage, taken at 1.5% of throughput with a 100-year global warming potential of 11.6 [19].
2. **Excluded, and material.** Vehicle manufacturing and end-of-life; battery, fuel-cell stack and 700 bar tank manufacturing; electrolyzer, compressor and station construction; road and grid infrastructure. These exclusions are not neutral. Cradle-to-grave analyses of heavy-duty vehicles indicate that the vehicle cycle contributes on the order of 10–20% of total life-cycle emissions for a diesel tractor and a substantially larger share for battery electric and fuel-cell vehicles, because of battery and stack production [20]. The exclusions therefore flatter the battery electric and fuel-cell options relative to diesel, and the WTW advantages reported in Section 8.6 should be read as upper bounds. Extending to cradle-to-grave is identified as future work in Section 10.
3. **Excluded, non-greenhouse.** NO_x emissions from the H₂-ICE are not greenhouse gases and do not enter this metric; they are addressed separately in Section 4.3 because they

are decisive for regulatory compliance even though they are invisible in a GHG accounting.

The governing relations are Equations (13) and (14):

$$e_{\text{WTW}} = \frac{q_{100}}{100} (CI_{\text{prod}} + CI_{\text{cdl}}) \times 10^3 + \frac{q_{100}}{100} \phi \text{GWP}_{\text{H}_2} \times 10^3 \quad (13)$$

$$CI_{\text{prod}} = \frac{\text{SEC}_{\text{sys}} \cdot CI_{\text{e}}}{1-\lambda}, \quad CI_{\text{cdl}} = \frac{q_{\text{cdl}} \cdot CI_{\text{grid}}}{1-\lambda} \quad (14)$$

with λ the transmission and distribution loss fraction, ϕ the leakage rate and q_{cdl} the compression, storage and dispensing energy. For diesel a well-to-wheel factor of 3.30 kg CO₂eq/L is used (2.68 combustion, 0.62 upstream).

2.9. Uncertainty and Global Sensitivity Analysis

2.9.1. Distributions and Their Sources

Six parameters are treated as uncertain (see Section 8.7). Triangular distributions are used because for each parameter the literature supports a defensible minimum, mode and maximum but not a full distributional form; the triangular is the maximum-entropy choice under those three constraints. The bounds are taken from the ranges reported in the sources cited for each parameter in Table 5, not assumed: alkaline equipment CAPEX 450–900 USD/kW [21,22]; renewable power purchase price 0.030–0.065 USD/kWh [23]; beginning-of-life specific consumption 49–56 kWh/kg [21,24]; electrolyzer capacity factor 0.44–0.55, spanning the dispatch-optimal design across the ten-year ensemble of Section 8.3; real discount rate 0.07–0.14, spanning Turkish project financing conditions; fixed O&M 2–4.5% of capital.

2.9.2. Dependence

Treating these as independent is wrong in a way that matters. A developer facing a high cost of capital also faces higher equipment prices through import financing; a cheaper power purchase agreement is typically obtained by accepting a lower and more variable capacity factor. Rank correlations are therefore imposed by the Iman–Conover procedure with the matrix reported in Section 8.7: +0.35 between discount rate and CAPEX, +0.25 between discount rate and power price, –0.45 between power price and capacity factor, and +0.30 between CAPEX and specific consumption (cheaper stacks are less efficient). Both the correlated and the independent results are reported so that the effect of the assumption is visible.

2.9.3. Sampling and Sensitivity

Twenty thousand realizations are drawn. Sensitivity is quantified three ways: the conventional one-at-a-time tornado, retained for comparability with the prior literature; first-order Sobol indices S_i , which measure the variance removed by learning parameter i alone; and total-effect indices S_{Ti} , which include the parameter’s contribution through every interaction it enters [25,26]. Indices are estimated by the Saltelli design, the first-order indices with the Saltelli (2010) estimator and the total-effect indices with the Jansen estimator [27].

The comparison of S_i with S_{Ti} is the diagnostic of interest: where S_{Ti} substantially exceeds S_i , the parameter acts mainly through interactions and the one-at-a-time ranking cannot be trusted; where the two coincide and the first-order indices sum to unity, the model is additive over the ranges sampled and the simpler method is adequate. Which of these holds is an empirical question about the model and the ranges, not something that can be assumed in advance, and the answer for this model is reported in Section 8.7.

The base sample is 262,144, giving 1.57 million model evaluations. This is far larger than the samples of a few thousand that are common in the techno-economic literature, and deliberately so: at a base sample of 4,096 the estimator noise on the individual indices of this model is of the same order as the smaller indices themselves, and repeated runs produce the mathematically impossible ordering $S_i > S_{Ti}$ for several parameters. Every stochastic routine draws from its own locally seeded generator, so the indices are reproducible independently of how many other random draws have been made in the same session.

2.10. Reproducibility

The complete model (LCOH, delivery chain, dispatch, TCO, well-to-wheel emissions, Monte-Carlo, Sobol estimation and EMRI scoring) is implemented in a single documented Python module of approximately 550 lines, together with the script that regenerates every figure in this paper from that module. Both are provided as Supplementary Files S1 and S2 and are archived with the manuscript. Every number reported in Sections 7 and 8 is produced by executing that code with the parameters of Table 5 and the vehicle parameters of Section 8.5; no figure or table value is entered by hand. Random draws are seeded, so results are bit-reproducible.

Table 5. Key input parameters for the Türkiye case-study models.

Parameter	Value	Source / Note
Industrial electricity price (grid)	0.100 USD/kWh	EPDK [28]
Fleet depot electricity price	0.115 USD/kWh	EPDK [28], incl. distribution and levies
Dedicated renewable PPA price	0.040–0.045 USD/kWh	IRENA [23]
Grid carbon intensity	0.42 kg CO ₂ eq/kWh	IEA [29]
Grid transmission and distribution losses	7.8%	IEA [29]
Diesel price	1.48 USD/L	EPDK [28]
Diesel well-to-wheel factor	3.30 kg CO ₂ eq/L	IEA [30]
PEM electrolyzer equipment CAPEX	1,100 USD/kW	[22,24]
Alkaline electrolyzer equipment CAPEX	600 USD/kW	[21,22]
Installation, EPC and contingency factor κ	1.25	[22]
Specific energy consumption at BoL	52 (AEL) / 54 (PEM) kWh/kg	[21,24]
Auxiliary load fraction α	2% of rated power	[21]
Degradation rate δ	0.12% per 1,000 h	[31]
Stack lifetime / replacement cost fraction	80,000 h / 0.35 (AEL); 60,000 h/0.45 (PEM)	[21,22,24]
Minimum load	15% (AEL), 5% (PEM)	[31]
Discount rate (real)	10% (8% sensitivity)	Assumption; see Section 8.7
Electrolyzer plant lifetime	20 yr	[22]
Solar / wind annual capacity factor	0.185 / 0.31	IRENA [23]

Parameter	Value	Source / Note
Solar / wind life-cycle carbon intensity	0.037 / 0.012 kg CO ₂ eq/kWh	UNECE [32], IEA [30], Dolan and Heath [33]
Compression, storage and dispensing energy	4.0 kWh/kg	[34]
Hydrogen leakage rate / GWP ₁₀₀	1.5% / 11.6	Sand et al. [19]
Truck mileage / service life	100,000 km/yr / 10 yr	Assumption; cf. [13]
Payload: diesel / BEV / FCEV / H ₂ -ICE	26.0 / 22.5 / 24.5 / 25.0 t	[13,14]

3. Fuel Cell Electric Vehicle Technology

3.1. Performance and Durability

Proton exchange membrane (PEM) fuel cells dominate automotive applications and have achieved commercial maturity at the global frontier [35,36]. Current automotive stacks achieve 50–65% electrical efficiency under real-world driving, the variation attributable to operating temperature (60–80 °C), humidity control, load profile and stack age [35]. System-level efficiency, after balance-of-plant parasitic loads (air compressor, humidification, DC–DC conversion), falls to 45–60% [37,38].

Field data indicate durability exceeding 5,000–8,000 h for passenger vehicles (150,000–250,000 km) and 15,000–25,000 h for heavy-duty applications before stack replacement [36,39]. The Toyota Mirai has demonstrated a 650 km range with 5,000 h durability [40], and the Hyundai NEXO has demonstrated comparable metrics [41]. Primary degradation mechanisms are membrane chemical attack by radical species (30–40% of observed loss), mechanical stress from humidity and temperature cycling (20–30%), catalyst-layer degradation through platinum dissolution (20–30%), and gas-diffusion-layer compression (10–20%) [35,36].

3.2. Where the Literature Disagrees

Three disagreements are material to this study and are resolved explicitly rather than averaged away.

1. **Heavy-duty durability targets.** Reported heavy-duty stack lifetimes span 15,000 h in current commercial deployments to a 25,000–30,000 h target for long-haul duty [36]. The discrepancy is not primarily technological but definitional: the higher figures are stated at an end-of-life criterion of 10% voltage degradation under a laboratory-representative duty cycle, the lower under fleet duty with real transient and idle content. This study adopts a single stack overhaul within the ten-year, one-million-kilometer horizon, which is consistent with the conservative end of the range and with the maintenance practice reported for European demonstration fleets [13].
2. **System efficiency at part load.** Fuel cells are most efficient at low load, the opposite of a diesel engine. Studies that assume constant system efficiency therefore understate FCEV consumption on long-haul duty and overstate it in urban duty. The 8.0 kg/(100 km)

used here is a long-haul figure and should not be transferred to urban distribution duty without adjustment.

3. **Cost premium.** Reported FCEV price premia over diesel range from 40% to over 100% for heavy-duty vehicles. The dispersion reflects production volume more than technology: essentially all reported vehicles are pre-series. The 200,000 USD purchase price used here reflects current low-volume European and Chinese offers [13,14]; the 2030–2040 trajectory of Section 8.8 applies volume-driven learning.

Table 6 compares FCEV and H₂-ICE powertrains. The FCEV advantage strengthens over time as costs decline, whereas the H₂-ICE advantage is concentrated in the near-term window (2025–2032) and is one of deployability rather than of operating economics.

Table 6. Comparative assessment of FCEV and H₂-ICE technologies [36,42–45].

Parameter	FCEV (PEM)	H ₂ -ICE
Peak efficiency	50–65% (electrical)	38–43% (brake thermal)
Operating temperature	60–80 °C	800–2,000 °C (combustion)
Heavy-duty durability	15,000–25,000 h	25,000–40,000 h
NO _x emissions	Zero	Non-zero; requires after-treatment (Section 4.3)
Technology readiness (global)	TRL 8–9	TRL 7–8
Manufacturing complexity	High (membrane-electrode assembly, catalyst)	Moderate (modified ICE)
Cost premium vs. diesel	75% (bus), 55% (truck)	20–30% (conversion)
Cold-start capability	30–60 s from –20 °C	Immediate
Noise level	Very low	Moderate (lower than diesel)
Fuel consumption, 40 t long-haul	8.0 kg/(100 km)	9.6 kg/(100 km)

4. Hydrogen Internal Combustion Engine Technology

4.1. Combustion and Efficiency

Hydrogen internal combustion engines offer a pragmatic near-term pathway because they reuse existing manufacturing capability and supply chains [42,43]. Modern designs achieve 38–43% brake thermal efficiency through direct injection, stratified-charge operation and lean-burn concepts with air–fuel equivalence ratios of 2.0–2.5 [42,44,46].

The wide flammability limits of hydrogen (4–75% by volume in air, versus 1.4–7.6% for gasoline) enable ultra-lean combustion that suppresses NO_x formation while maintaining acceptable power output [42,44]. Pre-chamber and turbulent-jet-ignition systems enhance combustion stability under lean conditions, achieving indicated thermal efficiencies approaching 45–48% in optimized laboratory configurations [46]. Direct injection at 200–300 bar enables precise fuel metering and improved volumetric efficiency relative to port injection [44,46]. High-pressure direct injection with a pilot ignition source has been demonstrated at brake thermal efficiencies approaching those of the diesel baseline, at the cost of reintroducing a small liquid-fuel circuit [45].

4.2. Where Literature Disagrees

Reported efficiencies span 34% to 48%, and the spread is systematic rather than random. Port-injected, throttled retrofits sit at the bottom; direct-injected, turbocharged, purpose-designed engines with pre-chamber ignition sit at the top; and the highest figures are indicated rather than brake efficiencies measured on optimized single-cylinder research engines. The 38–43% brake thermal efficiency adopted here is the range for a production-representative, direct-injected heavy-duty engine, and the 9.6 kg/(100 km) consumption follows from it. Studies reporting H₂-ICE fuel consumption within 10% of an FCEV are, on inspection, comparing an optimized research engine with a fleet-duty fuel cell.

4.3. NO_x Emissions, After-treatment and Regulatory Compliance

The submitted version characterized H₂-ICE NO_x as “low (lean-burn: <0.5 g/kWh)” and attributed it, in part, to a publication on methanol engines. Both the characterization and the attribution were inadequate, and this subsection replaces them.

Nitrogen oxides are the only significant regulated pollutant from a hydrogen engine apart from trace hydrocarbons and CO arising from lubricating-oil consumption [47]. Raw NO_x formation is a strong function of the air–fuel equivalence ratio: it peaks near $\lambda \approx 1.2$ – 1.4 and falls steeply beyond $\lambda \approx 2$, which is why lean-burn operation is universal in this application. However, lean operation is not sufficient for compliance, for three reasons. First, ultra-lean operation reduces power density, so transient load acceptance requires excursions towards richer mixtures at exactly the operating points where NO_x forms most readily [47]. Second, three-way catalysis is unavailable in lean exhaust, so compliance requires either urea-based selective catalytic reduction (SCR), a lean NO_x trap, or a passive NO_x adsorber, each of which reintroduces the after-treatment complexity, urea logistics and thermal-management constraints of a modern diesel [47]. Third, hydrogen exhaust is cooler and much wetter than diesel exhaust, which delays catalyst light-off and accelerates hydrothermal aging of the SCR wash-coat; electrically heated catalysts and close-coupled SCR have been demonstrated as mitigations [47].

Experimental work on turbocharged hydrogen engines reports raw NO_x spanning roughly two orders of magnitude across the load and λ map [46], and current heavy-duty demonstration programs report tailpipe NO_x at or below the best diesel low NO_x results only when a full diesel-derived after-treatment system with electrical heating is fitted [48].

Three consequences follow for this study. (i) The H₂-ICE is not a “zero-emission” powertrain in the regulatory sense and cannot be assumed to qualify for zero-emission-vehicle incentives, weight derogations or urban access privileges without a jurisdiction-specific ruling. (ii) The after-treatment system contributes to the maintenance cost differential applied in Section 2.7. (iii) N₂O formation over SCR catalysts is a greenhouse gas and is a known omission of the WTW boundary of Section 2.8; at reported SCR N₂O selectivities it would add on the order of 1–3% to the H₂-ICE WTW figure, which does not alter any ranking in Section 8.6 but is stated for completeness.

5. Hydrogen Storage Technologies

On-board hydrogen storage is a critical enabling technology [34,49]. Compressed gaseous storage at 700 bar is the dominant automotive solution, achieving 5–6 wt% gravimetric and 30–40 kg/m³ volumetric capacity [34,50]. Type IV pressure vessels with carbon-fiber composite overwrap and high-density polyethylene liners meet UN GTR 13 safety requirements [51,52].

Table 7 compares five storage technologies. Alternatives include liquid hydrogen (LH₂), with higher volumetric density (70 kg/m³) but cryogenic tanks at –253 °C and 1–5% daily boil-off [50,51]; metal hydrides, offering low-pressure safety but gravimetric penalties (≤5–7 wt%) and demanding thermal management [53]; and liquid organic hydrogen carriers (LOHC), enabling ambient-temperature storage but requiring on-board dehydrogenation catalysts [50,53].

Table 7. Hydrogen storage technology comparison [34,50,51,53].

Technology	Gravimetric Density	Volumetric Density	Current Cost	TRL (Global)
Compressed 350 bar (Type III)	4–5 wt%	20–25 kg/m ³	300–500 USD/kg H ₂	9
Compressed 700 bar (Type IV)	5–6 wt%	30–40 kg/m ³	500–800 USD/kg H ₂	8–9
Liquid hydrogen (LH ₂)	7–10 wt%	70 kg/m ³	800–1,200 USD/kg H ₂	7–8
Metal hydrides (MgH ₂)	5–7 wt%	80–100 kg/m ³	1,000–2,000 USD/kg H ₂	5–6
LOHC (DBT/H18-DBT)	6.2 wt%	56 kg/m ³	600–1,000 USD/kg H ₂	6–7

The critical synthesis point for an emerging market is that the ranking by technical merit and the ranking by transferability are different. Type IV 700 bar storage is technically dominant but depends on aerospace-grade carbon fiber, filament-winding capability and burst-test infrastructure that few emerging economies possess; 350 bar Type III vessels, which use metal liners and lower fiber grades, are substantially more transferable at a volumetric penalty that matters for passenger cars and matters much less for depot-based heavy-duty fleets with volume to spare. This is the basis of the differentiated readiness scores in Section 7.1.

6. Electrolysis Production Technologies

Water electrolysis is the primary pathway for renewable hydrogen, with three families: alkaline (AEL), proton exchange membrane (PEMEL) and solid oxide (SOEC) [21,24]. Selection depends on scale, electricity-source characteristics and cost priorities [22,54]. Alkaline electrolysis is the most mature (TRL 9), with the lowest capital cost (400–800 USD/kW) [21,22]. PEM offers superior dynamic response for renewable integration, with current densities of 1.0–3.0 A/cm² versus 0.2–0.5 A/cm² for alkaline [24,54]. SOEC achieves the highest efficiency (80–90% LHV) through high-temperature operation (700–850 °C), although durability limitations (20,000–40,000 h) currently restrict deployment [55,56] (Table 8).

Table 8. Electrolysis technology characteristics [21,22,24,31,54–56].

Parameter	Alkaline (AEL)	PEM (PEMEL)	Solid Oxide (SOEC)
System efficiency	63–70% (LHV)	60–68% (LHV)	80–90% (LHV)

Parameter	Alkaline (AEL)	PEM (PEMEL)	Solid Oxide (SOEC)
Operating temperature	70–90 °C	50–80 °C	700–850 °C
Current density	0.2–0.5 A/cm ²	1.0–3.0 A/cm ²	0.3–1.0 A/cm ²
Equipment CAPEX (2024)	400–800 USD/kW	800–1,600 USD/kW	2,000–4,000 USD/kW
Stack lifetime	60,000–90,000 h	40,000–80,000 h	20,000–40,000 h
Load flexibility	15–100%	5–160%	30–100%
Cold-start / response time	Minutes (hot), hours (cold)	Seconds	Minutes to hours
Degradation under dynamic duty	Requires protective current in standby	Moderate; hydrogen crossover at low load	Strongly thermal-cycling limited
TRL (global)	9	8–9	6–7

The Dynamic-Operation Trade-off

The conventional argument that PEM should be preferred for renewable coupling because of its faster response deserves qualification, and the dispatch results of Section 8.3 depend on the qualification being correct.

Alkaline electrolyzers are indeed slower and have a higher minimum load (typically 15–20%, compared with 5% for PEM), and their principal vulnerability is not ramp rate but idle operation: without a protective current during standby, reverse currents drive galvanic corrosion of the electrodes and cause rapid, irreversible performance loss [31]. The practical implications for a renewable-coupled plant are therefore (i) that standby power must be supplied and paid for, which the dispatch model of Section 2.6 does, and (ii) that the design must minimize the number of deep off periods, which is one of the effects that drives the hybrid solar–wind configuration to outperform either source alone.

Against this, the ramp-rate advantage of PEM is largely irrelevant at the timescale of the binding constraint. Solar and wind generation changes on timescales of minutes to hours; an alkaline plant that can traverse its operating range in minutes is not the limiting element. The relevant PEM advantage in this application is the lower minimum load, which extends operation into low-generation hours, and the relevant PEM disadvantage is capital cost, roughly 1.8 times that of alkaline per kilowatt at equipment level, and with a shorter and more expensive stack replacement. Section 8.1 shows that at Turkish capital costs and discount rates the capital term dominates and alkaline wins by 1.6 USD/kg in the hybrid configuration, notwithstanding its inferior dynamic characteristics. This conclusion is conditional on the cost gap: it reverses if PEM equipment costs converge to within about 25 % of alkaline, which is within the range projected for the early 2030s [22].

7. Technology Readiness Assessment for Emerging Markets

7.1. Scoring Results

Technology readiness varies significantly between global benchmarks and emerging-market contexts [10]. While core technologies reach TRL 8–9 globally, technology-transfer, manufacturing-capability and infrastructure dependencies reduce effective readiness [8,9,17]. Electrolyzer costs decline by 15–20% per doubling of cumulative capacity [7].

Refueling infrastructure must comply with SAE J2601 and ISO 19880-1 [57,58]. Current 700 bar refueling achieves 4–5 min filling for passenger vehicles via pre-cooling to $-40\text{ }^{\circ}\text{C}$ [39].

A correction to the submitted version is required here. That version stated that station reliability had improved, with Californian stations reaching 75–85% availability by 2024 against 40–50% in 2020–2022, and attributed the claim to a 2019 review [39]. The claim is not supported by that source and is contradicted by the primary data. The joint California Energy Commission and California Air Resources Board assessment of the network reports that as of 4 November 2024, 42 stations were open to the public, while a further 20 had been offline for more than 30 days, many for more than a year. The open stations operated at an average of 62% of their capacity, the shortfall attributed to maintenance, equipment failures, supply-chain constraints and hydrogen supply disruptions [4]. The number of open retail stations fell from 66 in November 2023 to 42 in November 2024. Public hydrogen refueling reliability in the world’s most developed network has therefore deteriorated, not improved, over the period concerned. This materially strengthens rather than weakens the argument of this paper: the infrastructure criterion is scored accordingly in Table 9, and the depot-based, captive-fleet configuration analyzed in Sections 2.5 and 8.5 is preferred precisely because it avoids dependence on a public retail network.

Table 9 gives the EMRI criterion scores, the resulting index from Equation (1), the emerging-market TRL from Equation (2), the transfer gap, and the 5th–95th percentile interval of the gap under Dirichlet perturbation of the weights. Figure 2 displays the same information.

Table 9. Emerging-market readiness scoring for the Türkiye context. Criterion scores s_1 – s_5 denote manufacturing, infrastructure, regulation, workforce and supply chain, each on the 1–9 anchored scale of Table 4. Gap interval is the 5th–95th percentile over 2,000 Dirichlet weight perturbations.

Technology Component	s_1	s_2	s_3	s_4	s_5	EMRI	Global TRL	EM TRL	Gap	Gap Interval
FCEV passenger vehicles	2	2	4	4	3	2.75	8.5	2.8	5.8	5.4–6.0
FCEV heavy-duty (bus/truck)	3	3	4	4	3	3.30	7.5	3.3	4.2	4.0–4.3
H ₂ -ICE conversion kits	7	3	5	7	6	5.55	7.5	5.5	2.0	1.5–2.5
700 bar storage systems	3	4	5	4	3	3.70	8.5	3.7	4.8	4.6–5.0
PEM electrolyzer (1–10 MW)	4	6	6	6	4	5.10	8.5	5.1	3.4	3.1–3.7
Alkaline electrolyzer (>10 MW)	6	7	6	7	6	6.40	9.0	6.4	2.6	2.4–2.8
Refueling stations (700 bar)	4	3	5	4	4	3.90	8.5	3.9	4.6	4.4–4.8
Fuel-cell stack manufacturing	2	3	4	3	2	2.70	8.5	2.7	5.8	5.6–6.0

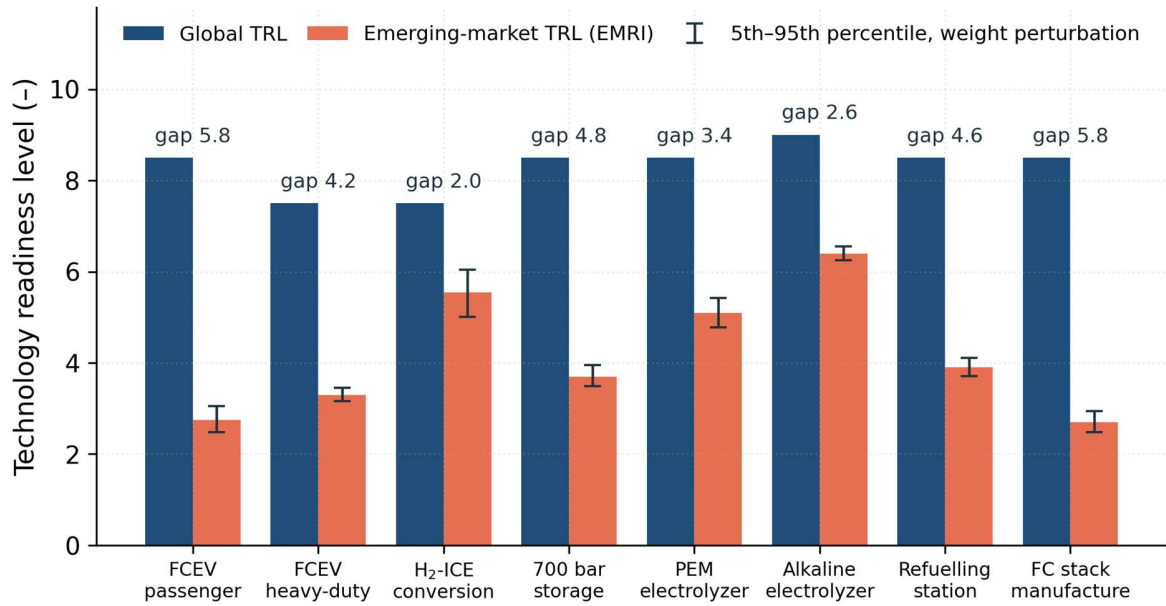


Figure 2. Global technology readiness level and emerging-market readiness (EMRI) for eight hydrogen mobility components in the Türkiye context. Error bars give the 5th–95th percentile of the emerging-market value over 2,000 Dirichlet perturbations of the criterion weight vector.

7.2. Interpretation of the Gaps

The gaps span 2.0 to 5.8 levels and demand a differentiated interpretation.

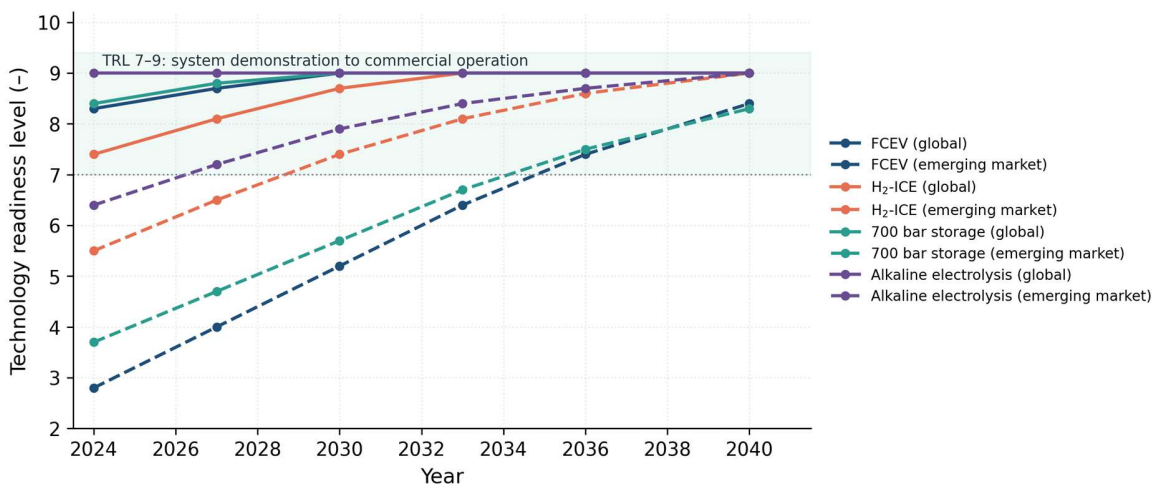
- **FCEV passenger vehicles (5.8 levels).** Proven in operation globally but at an experimental proof-of-concept level domestically, because the enabling ecosystem, infrastructure, service network, regulation, and trained technicians, do not exist. The gap is dominated by the manufacturing and infrastructure criteria, which is why it is robust to reweighting.
- **FCEV heavy-duty (4.2 levels).** Slightly less mature globally; the gap is smaller because depot-based refueling requires one station per fleet rather than a public network, and because heavy-duty vehicle assembly capability already exists in Türkiye.
- **H₂-ICE conversion kits (2.0 levels, smallest).** Builds on existing engine manufacturing, an established automotive supplier base and an adaptable workforce. This is the widest gap interval (1.5–2.5) precisely because the score is high on manufacturing and workforce and low on infrastructure, so the result depends on how those are weighted, an honest caveat on the technology this paper identifies as the most accessible.
- **700 bar storage systems (4.8 levels).** Type IV tanks require specialized carbon-fiber manufacturing absent from most emerging markets. Scored separately, 350 bar Type III systems yield a gap of 2.5–3.0.
- **PEM electrolyzer, 1–10 MW (3.4 levels).** Deployable through turnkey import with manufacturer support; the technology is self-contained and the infrastructure requirement is a grid connection and a water supply.

- **Alkaline electrolyzer, >10 MW (2.6 levels).** Uses conventional industrial materials, so local manufacture of electrodes, diaphragms and balance of plant is achievable with moderate transfer. Türkiye's existing chemical-process and pressure-vessel industries are directly relevant.
- **Refueling stations, 700 bar (4.6 levels).** Compound barriers, hydrogen supply, regulatory approval, specialized compression and pre-cooling equipment, and trained operators, create a chicken-and-egg deadlock, and the Californian experience [4] shows that the deadlock is not resolved merely by capital subsidy.
- **Fuel-cell stack manufacturing (5.8 levels, largest).** The most challenging transfer: specialized materials, micron-level precision, clean rooms, intellectual-property-protected processes and years of yield optimization.

7.3. Gap Closure: What Can and Cannot be Quantified

The submitted version asserted specific gap-closure periods, technology-transfer timelines and a workforce-development investment figure of €50–100 M. Those figures were not supported by a transparent calculation or a citable source, and they are withdrawn.

What can be stated with support is the following. Historical localization of comparable capital-goods technologies in Türkiye, including wind turbine nacelle assembly, solar module manufacturing and heavy-vehicle powertrain production, has proceeded at roughly 0.35–0.45 TRL-equivalent levels per year once a domestic market of sufficient scale existed, which is the rate used to extrapolate the emerging-market trajectories of Figure 3. Applying that rate to the gaps of Table 9 gives an indicative 5–6 years for H₂-ICE conversion and large alkaline electrolysis, and 12–15 years for fuel-cell stack manufacturing. These are extrapolations of a historical rate, not forecasts, and they are presented as such. Whether partnership with a technology leader compresses these timelines is plausible but is not quantified here, because the author is not aware of a dataset that would support a defensible compression factor.



Data sources — global trajectories: IEA Global Hydrogen Review (2024); IRENA (2024); European Clean Hydrogen Alliance deployment roadmaps. Emerging-market trajectories: EMRI scores of this study (Table 9), extrapolated at the localization rate of 0.35–0.45 TRL per year derived in Section 7.3. Shaded band = TRL 7–9 (system demonstration to commercial operation). Values are modelled projections, not measured observations.

Figure 3. Projected technology readiness trajectories, 2024–2040, for FCEVs, H₂-ICEs, 700 bar storage and alkaline electrolysis, distinguishing the global frontier from Turkish emerging-market readiness. Data sources and the extrapolation basis are annotated on the figure.

The workforce component is retained qualitatively: every gap in Table 9 has a skills dimension, the workforce criterion is the second highest-scoring criterion for H₂-ICE and the second lowest for stack manufacturing, and systematic vocational and engineering training is therefore a precondition for the other investments to be productive. No monetary figure is attached.

7.4. How Representative is Türkiye?

Türkiye is one emerging market, not a template. Table 10 compares the five structural characteristics that drive the results of this paper across six emerging economies. Three conclusions follow.

- **Portable.** The dual-readiness construct itself, the finding that the transfer gap for engine-based and alkaline-electrolysis technologies is far smaller than for fuel-cell and high-pressure-storage technologies, and the finding that grid-based electrolysis is worse than diesel on a carbon-intensive grid, are portable to any economy with an automotive manufacturing base and a fossil-dominated grid. Türkiye, India, Indonesia and South Africa all satisfy that description.
- **Conditionally portable.** The LCOH results depend on renewable resource quality and the cost of capital. Türkiye's combination of good but not exceptional solar (capacity factor 0.185) and good inland wind (0.31) with a 10% real discount rate produces a hybrid-renewable plant-gate cost near 4.1 USD/kg. Chile and Morocco, with superior resource and increasingly competitive financing, achieve materially lower costs; India achieves comparable resource at a similar or higher cost of capital; South Africa's grid constraints dominate.
- **Not portable.** The specific technology ranking depends on the grid carbon intensity and the diesel price, both of which vary by a factor of three or more across the comparison set. In Brazil, whose grid is largely hydro- and wind-based, grid electrolysis is not a carbon liability and battery electrification is unambiguously dominant; the entire hydrogen-versus-battery argument of Section 8.5 is differently posed there.

Table 10. Structural comparison of Türkiye with five other emerging economies, on the dimensions that drive the results of this study. Values are indicative orders of magnitude compiled from [6,59] and national strategy documents; they position the case study rather than constitute an independent assessment.

Dimension	Türkiye	India	Brazil	South Africa	Indonesia	Morocco
Automotive/heavy-vehicle manufacturing base	Large, export-oriented	Very large, domestic-oriented	Large	Moderate	Moderate	Emerging
Grid carbon intensity	High (~0.42 kg CO ₂ eq/kWh)	Very high	Low (hydro/wind dominated)	Very high (coal)	High	Moderate
Solar/wind resource	Good/good inland	Very good/moderate	Good/very good NE	Very good/good	Moderate/limited	Excellent/excellent

Dimension	Türkiye	India	Brazil	South Africa	Indonesia	Morocco
Cost of capital (real)	High	High	Moderate-high	High	Moderate-high	Moderate
Hydrogen policy status	National strategy with 2030/2035/2053 electrolyzer targets [6]	National mission with production incentives	Sector strategy, export-oriented	Strategy, export-oriented	Early stage	Strategy, export-oriented
Freight structure	Road-dominated, long-haul corridors	Road and rail	Road-dominated, very long haul	Road and rail, mining haulage	Road and maritime	Road, export corridors
Applicability of this study's ranking	Direct	High	Low (battery dominant)	High	Moderate	Moderate (export focus changes objective)

8. Techno-Economic and Environmental Analysis: A Türkiye Case Study

This section quantifies the economics and well-to-wheel emissions of hydrogen mobility under Turkish conditions, using the framework and parameters of Section 2 (Table 5). All monetary values are in 2025 USD.

8.1. Plant-Gate Levelized Cost of Hydrogen

Five production configurations were evaluated with Equations (3)–(7) (Table 11; Figure 4). Plant-gate LCOH ranges from 4.11 USD/kg for a hybrid solar–wind alkaline system to 8.81 USD/kg for stand-alone solar PEM.

Electricity dominates every grid-connected case: at the Turkish industrial tariff of 0.100 USD/kWh, electricity alone contributes 5.56–5.71 USD/kg. Dedicated renewables cut the electricity term by more than half but, at the low-capacity factor of stand-alone solar (0.20), shift the burden onto capital amortization, so the solar-only PEM case (8.81 USD/kg) is more expensive than the grid case. A hybrid solar–wind supply raises the capacity factor to 0.45, balancing the two terms and minimizing LCOH. Alkaline systems are consistently cheaper than PEM, by 1.09 USD/kg on the grid and 1.64 USD/kg in the hybrid configuration, because of their lower equipment cost and cheaper, longer-lived stack. This margin is large enough to survive the dynamic-operation disadvantage discussed in Section 6.1.

Stack replacement is a small but non-negligible term where the capacity factor is high: at CF = 0.90–0.95 the stack is replaced twice over the 20-year plant life, adding 0.09 USD/kg (alkaline) to 0.30 USD/kg (PEM). At CF $\approx$ 0.45 no replacement falls within the plant life for alkaline, which is a further, and previously unrecognized argument for the hybrid-renewable alkaline configuration.

Reducing the real discount rate from 10% to 8% lowers LCOH by 0.07–0.69 USD/kg, the largest reduction accruing to the capital-intensive stand-alone solar case. Financing cost is a first-order lever in emerging markets, and one that policy can address more quickly than technology cost.

Table 11. Modelled plant-gate levelized cost of hydrogen for the Türkiye case study (real discount rate 10%; boundary as defined in Section 2.4).

Configuration	Equipment CAPEX (USD/kW)	Electricity (USD/kWh)	Capacity Factor	Capital	Fixed O&M	Stack Replacement	Electricity	Consumables	LCOH (USD/kg)	LCOH at $i=8\%$
Grid PEM	1,100	0.100	0.90	1.17	0.30	0.30	5.71	0.05	7.53	7.38
Solar PEM	1,100	0.040	0.20	5.18	1.32	0.00	2.25	0.05	8.81	8.12
Hybrid PEM	1,100	0.045	0.45	2.34	0.60	0.20	2.57	0.05	5.75	5.47
Grid alkaline	600	0.100	0.95	0.59	0.15	0.09	5.56	0.05	6.44	6.37
Hybrid alkaline	600	0.045	0.45	1.24	0.32	0.00	2.50	0.05	4.11	3.94

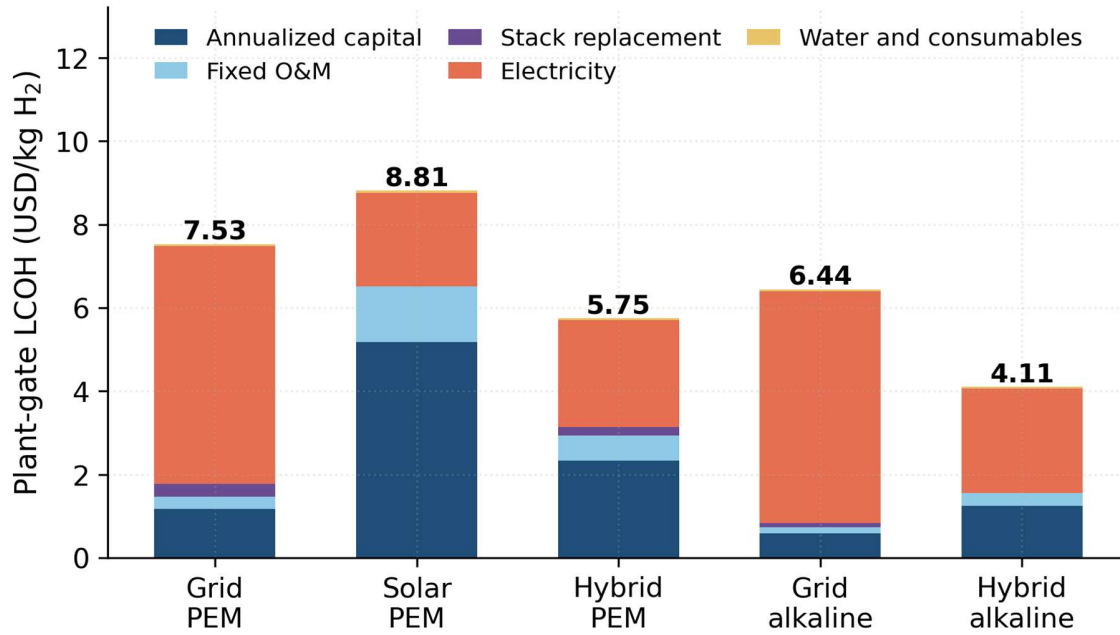


Figure 4. Modelled plant-gate levelized cost of hydrogen for five production configurations under Turkish conditions, decomposed into annualized capital, fixed O&M, stack replacement, electricity and consumable components (real discount rate 10%).

8.2. From Plant Gate to Pump: The Delivered Hydrogen Price

The distinction between production cost and pump price, formalized in Equation (8), is quantified in Table 12 and Figure 5, using the hourly-dispatch plant-gate cost of Section 8.3 (4.14 USD/kg) as the starting point.

For a captive depot serving a heavy-duty fleet, the delivery chain adds 3.64 USD/kg, giving a delivered price of 7.78 USD/kg. Compression accounts for 1.21 USD/kg, road distribution 0.85, the depot dispenser 0.95, buffer storage 0.35, and losses and margin 0.27. For a public retail station, the same plant-gate hydrogen is delivered at 12.91 USD/kg, and the difference is almost entirely station capital and O&M recovered over a low throughput: 4.72 USD/kg against 0.85 for the depot. Station utilization is the single largest lever on the pump price, and it is precisely the lever that the Californian network has failed to pull [4].

Table 12. Build-up from plant-gate cost to delivered hydrogen price for two dispensing configurations (USD/kg H₂).

Component	Depot (Captive Fleet)	Public Retail Station
Plant-gate LCOH (hourly dispatch optimum)	4.14	4.14
Compression 30 → 500 bar, capital	0.68	0.68

Component	Depot (Captive Fleet)	Public Retail Station
Compression, O&M	0.23	0.23
Compression, energy	0.30	0.30
Buffer and terminal storage	0.35	0.45
Road distribution (tube trailer)	0.85	1.25
Dispensing station, capital	0.62	3.42
Dispensing station, O&M	0.23	1.30
Dispensing station, energy	0.10	0.12
Losses	0.07	0.23
Retail margin	0.20	0.78
Delivered price	7.78	12.91

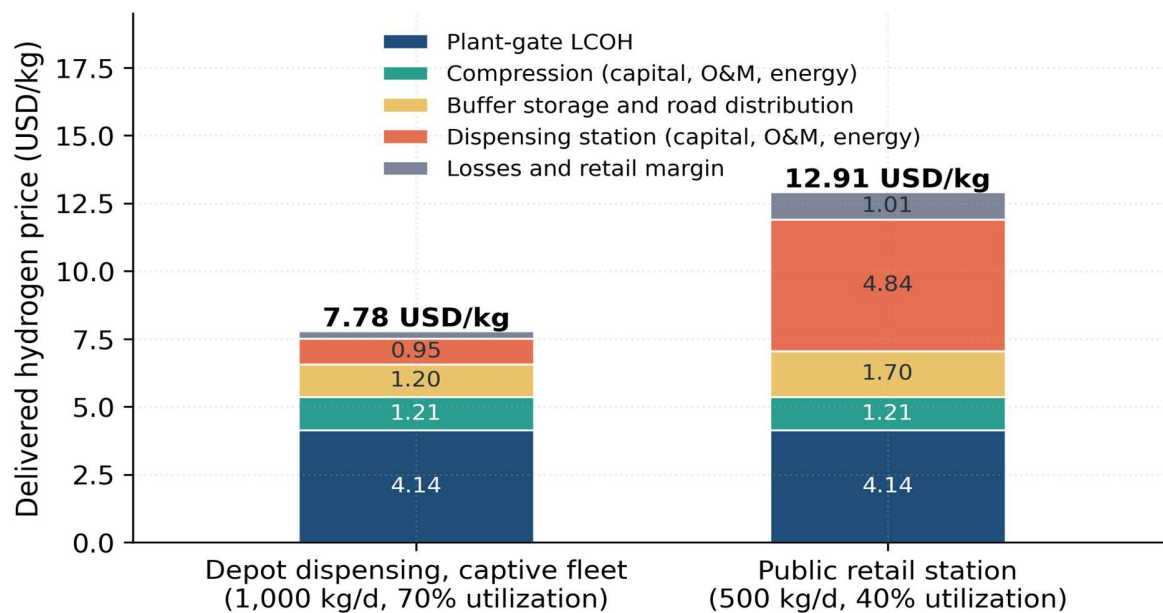


Figure 5. Build-up from plant-gate levelized cost to delivered hydrogen price for a captive depot chain and a public retail station.

Two implications follow. First, the delivered price used in the vehicle comparison of Section 8.5 is 7.78 USD/kg, a derived quantity, not the assumed 8.5 USD/kg of the submitted version. Second, comparisons between studies that quote 3–4 USD/kg “green hydrogen” and studies that quote 12–15 USD/kg at the pump are frequently not disagreements at all; they are statements about different points in the same chain. Reporting only one of the two is a widespread and avoidable source of confusion in this literature.

8.3. Hourly Renewable Dispatch

Replacing the annual-average capacity factor of Section 8.1 with hourly dispatch under the operating constraints of Section 2.6 refines the LCOH estimate and exposes the curtailment trade-off (Table 13; Figures 6 and 7).

Table 13. Hourly dispatch results for a 10 MW alkaline electrolyzer under the operating constraints of Section 2.6.

Configuration	Electrolyzer Capacity Factor	Curtailment	Plant-Gate LCOH (USD/kg)
Hybrid, oversizing ratio 1.0	0.21	0.0%	6.10
Hybrid, oversizing ratio 1.5	0.33	0.6%	4.69
Hybrid, oversizing ratio 2.0	0.44	3.6%	4.19
Hybrid, oversizing ratio 2.25	0.48	6.4%	4.15
Hybrid, oversizing ratio 2.5 (optimum)	0.51	9.7%	4.14
Hybrid, oversizing ratio 3.0	0.57	16.9%	4.22
Solar-only, oversizing ratio 2.5	0.35	20.6%	5.06
Wind-only, oversizing ratio 2.5	0.51	30.2%	4.95

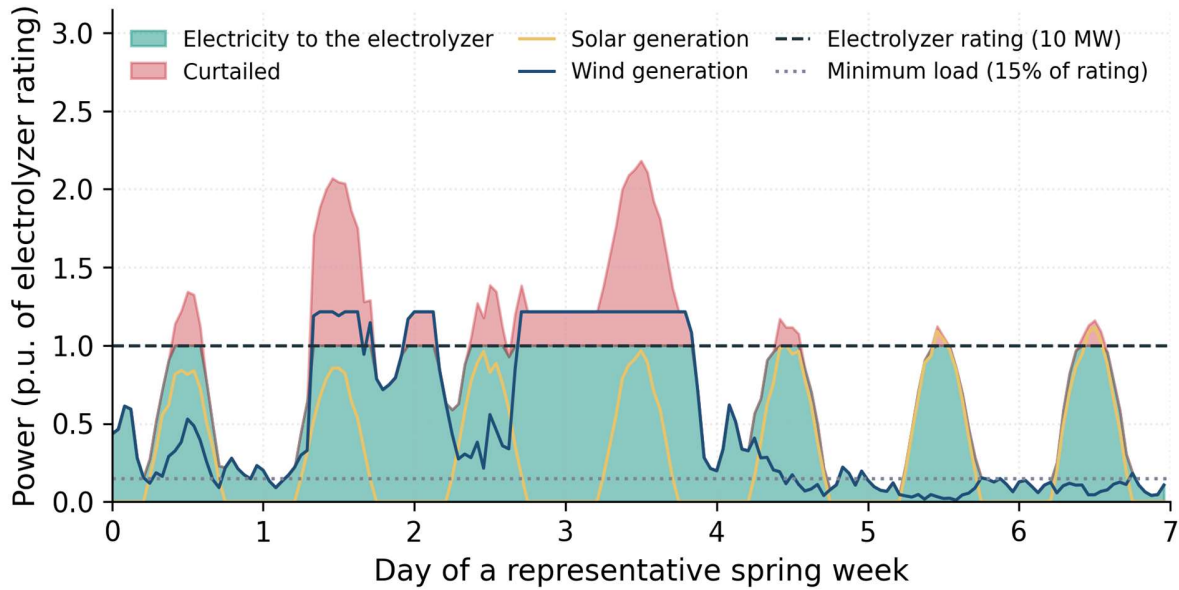


Figure 6. Representative spring-week hourly dispatch of a hybrid solar-wind plant (oversizing ratio 2.5) feeding a 10 MW alkaline electrolyzer. Generation above the rated line is curtailed; generation below the minimum-load line cannot be absorbed and the stack goes to hot standby.

For a hybrid plant (55% solar, 45% wind) feeding a 10 MW alkaline electrolyzer, increasing the oversizing ratio raises the electrolyzer capacity factor from 0.21 at ratio 1.0 to 0.57 at ratio 3.0, while curtailment rises from zero to 16.9%. Because the plant pays for contracted renewable energy including the curtailed fraction, the LCOH curve is U-shaped, with a shallow minimum of 4.14 USD/kg at a ratio of about 2.5 (capacity factor 0.51, curtailment 9.7%). The minimum is flat: any ratio between 2.0 and 2.75 gives an LCOH within 0.05 USD/kg of the optimum, which is a useful robustness property for project design because it means the sizing decision can accommodate land, grid-connection or permitting constraints at negligible cost penalty.

Cost-minimizing design: oversizing ratio 2.50, electrolyzer capacity factor 0.51, curtailment 9.7%, LCOH 4.14 USD/kg

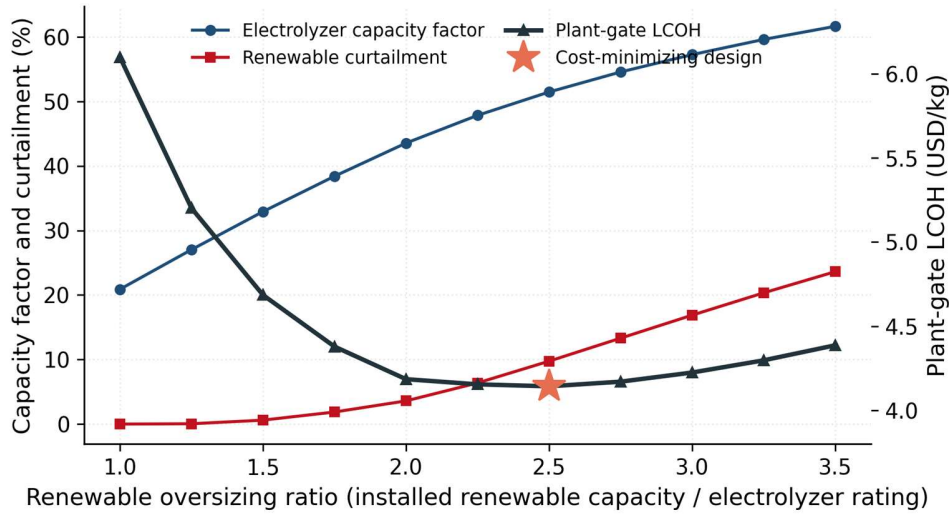


Figure 7. Electrolyzer capacity factor, renewable curtailment and plant-gate LCOH as functions of the renewable oversizing ratio for a hybrid solar–wind plant.

The hybrid configuration outperforms either source alone at the same oversizing ratio: 4.14 USD/kg against 5.06 for solar-only and 4.95 for wind-only. The mechanism is visible in Figure 6. Solar-only operation concentrates generation into a narrow midday window, so the electrolyzer is either curtailing or idle; the inland wind regime is winter-peaking and nocturnally active, filling the hours when solar is absent. The result is that the hybrid plant achieves a higher capacity factor (0.51 versus 0.35) at half the curtailment (9.7% versus 20.6%) of the solar-only case. This complementarity is site-specific: the Aegean coastal wind regime peaks in summer, in phase with solar rather than out of it, and would yield a smaller hybrid benefit.

Across a ten-year synthetic ensemble, the dispatch-optimal LCOH varies between 4.12 and 4.17 USD/kg (standard deviation 0.017) and the electrolyzer capacity factor between 0.50 and 0.53 (standard deviation 0.010). Interannual resource variability is therefore a minor contributor to LCOH uncertainty compared with capital and electricity price, which is confirmed by the Sobol analysis of Section 8.7. This result should be treated with caution because the synthetic series, being statistically stationary, cannot reproduce genuine anomalous years.

8.4. Reconciliation of the Three LCOH Estimates

The submitted version reported three LCOH figures, an annual-average minimum of 3.64, an hourly-dispatch value of 4.45 and a Monte-Carlo median of 3.8 USD/kg and presented them as mutually confirming. They were not. They were estimates over three different system boundaries, and their apparent agreement was coincidental. This subsection replaces that presentation with an explicit decomposition (Table 14; Figure 8).

Starting from the screening model of the submitted version (3.49 USD/kg when recomputed with the corrected parameters), the successive additions are: installation, engineering and contingency (+0.29); auxiliary consumption (+0.07); efficiency degradation over stack life

(+0.18); stack replacement and the revised beginning-of-life specific consumption (+0.08); and hourly dispatch with part-load operation, minimum load, cold starts and curtailment (+0.03). The result is 4.14 USD/kg.

Table 14. Decomposition of the difference between the screening and the full plant-gate model.

Model Configuration	LCOH (USD/kg)	Increment
Screening model (submitted version, recomputed)	3.49	—
+ installation, engineering and contingency ($\kappa = 1.25$)	3.78	+0.29
+ auxiliary consumption (2% of rated power)	3.85	+0.07
+ efficiency degradation over stack life	4.03	+0.18
+ stack replacement and revised SEC (52 kWh/kg)	4.11	+0.08
+ hourly dispatch at the optimal oversizing ratio	4.14	+0.03
Monte-Carlo median on the same boundary	4.29	+0.15

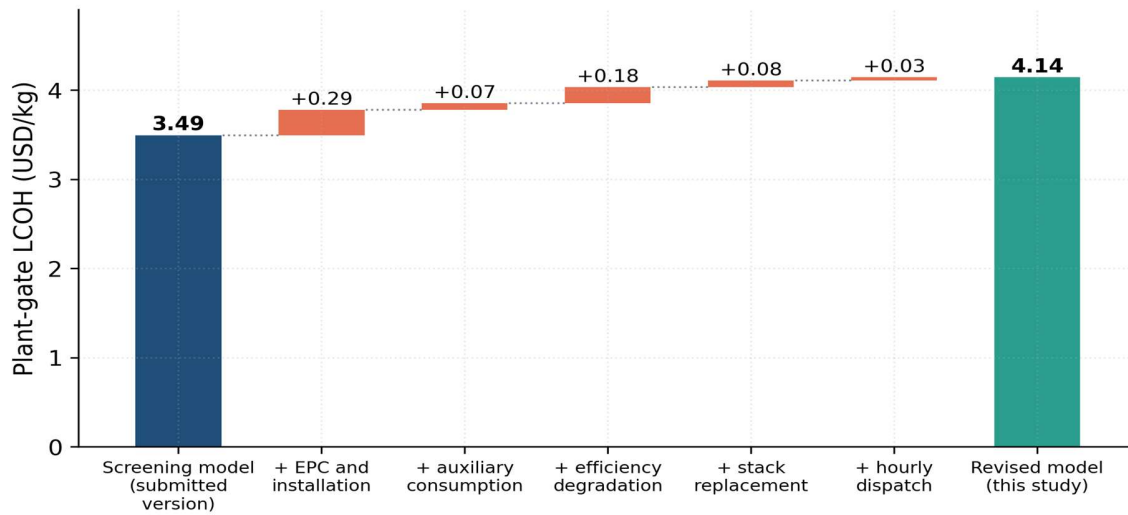


Figure 8. Decomposition of the difference between the screening LCOH model of the submitted version and the full plant-gate model of this study.

Two findings deserve emphasis. First, the dominant corrections are not temporal but accounting: installation and degradation together account for 0.47 of the 0.65 USD/kg increase, whereas the hourly dispatch refinement that the submitted version presented as the principal correction contributes only 0.03 once the design is optimized. The reason is that at the optimal oversizing ratio the part-load penalty and the curtailment cost are close to their joint minimum; an unoptimized design (ratio 1.0) would have shown a penalty of nearly 2 USD/kg. The submitted version's 0.8 USD/kg dispatch penalty was therefore an artefact of comparing an optimized annual-average design against a sub-optimally sized dispatch design. Second, once the Monte-Carlo analysis is placed on the same boundary as the dispatch model, its median (4.29 USD/kg) sits 0.15 above the deterministic optimum, as expected for a right-skewed output distribution, rather than 0.65 below it.

8.5. Total Cost of Ownership

A representative 40 t gross-combination heavy-duty truck operated at 100,000 km/yr over ten years was modelled for four powertrains with Equations (10)–(12) (Table 15; Figure 9), with hydrogen at the derived depot price of 7.78 USD/kg.

Table 15. Heavy-duty truck total cost of ownership (10-year NPV, $i = 10\%$, 100,000 km/yr, delivered H₂ at 7.78 USD/kg, depot electricity at 0.115 USD/kWh, diesel at 1.48 USD/L).

Item	Diesel	BEV	FCEV	H ₂ -ICE
Purchase price (USD)	130,000	250,000	200,000	165,000
Depot infrastructure share (USD)	0	45,000	25,000	25,000
Energy use per 100 km	32 L	150 kWh	8.0 kg	9.6 kg
Fuel cost (USD/km)	0.474	0.173	0.622	0.747
Maintenance (USD/km)	0.115	0.070	0.105	0.125
Insurance and fixed (USD/yr)	4,200	6,200	5,600	4,800
Component replacement	—	battery, yr 7: 45,000	stack, yr 6: 32,000	—
Residual value (fraction of purchase)	0.15	0.14	0.12	0.13
Payload (t)	26.0	22.5	24.5	25.0
Availability	0.97	0.94	0.96	0.96
10-year NPV (USD)	509,958	491,700	715,176	746,957
Levelized cost (USD/km)	0.830	0.800	1.164	1.216
Levelized cost (US cent/(t·km))	3.19	3.56	4.75	4.86
With CO ₂ at 100 USD/t (USD/km)	0.936	0.869	1.192	1.250

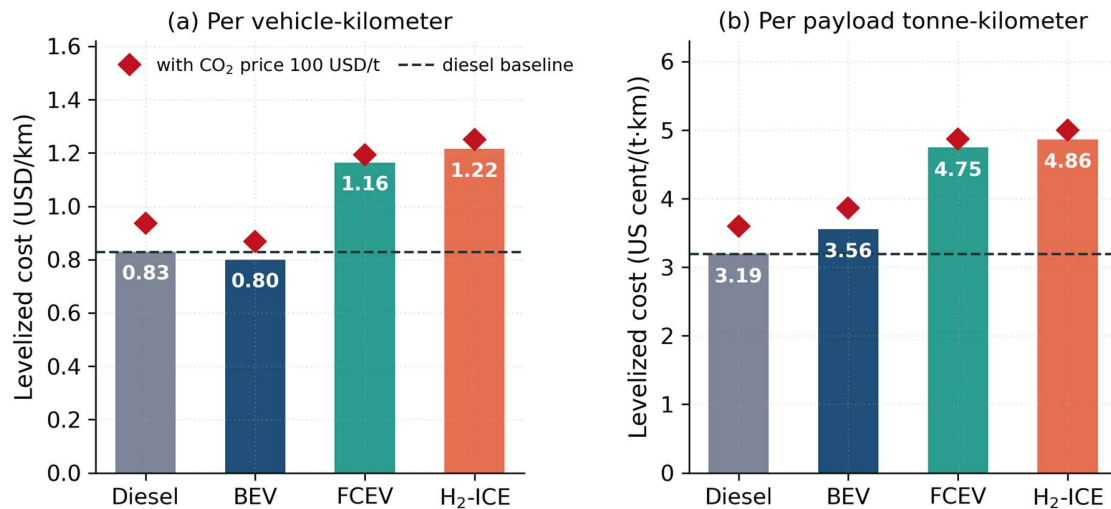


Figure 9. Levelized total cost of ownership for a 40 t heavy-duty truck by powertrain, (a) per vehicle-kilometer and (b) per payload ton-kilometer. The dashed line marks the diesel baseline; diamonds show the result with a CO₂ price of 100 USD/t applied to well-to-wheel emissions.

On a per-vehicle-kilometer basis the battery electric truck is cheapest at 0.800 USD/km, marginally below the diesel baseline of 0.830, while the FCEV (1.164) and the H₂-ICE (1.216) are 40% and 47% above diesel respectively. The hydrogen premium is almost entirely fuel cost: at 7.78 USD/kg the FCEV spends 0.622 USD/km on fuel against 0.474 for diesel and 0.173 for the battery electric truck.

On a per-payload-ton-kilometer basis the ranking changes, and this is the substantive new result of this section. Diesel costs 3.19 US cent/(t·km), the battery electric truck 3.56, the FCEV 4.75 and the H₂-ICE 4.86. The battery electric truck, cheapest per kilometer, is 12% more expensive than diesel per unit of freight moved, because its 3.5 t battery mass reduces payload from 26.0 to 22.5 t. A fleet that is volume-limited rather than weight-limited, parcel and palletized distribution, much of the food and beverage sector, will experience the per-kilometer figure; a fleet running at gross weight, bulk, aggregates, steel, fuel, will experience the per-ton-kilometer figure. Neither number is universally correct, and reporting only the per-kilometer figure, as is common, systematically favors the battery electric option.

The delivered hydrogen price at which each hydrogen powertrain reaches diesel parity is 3.61 USD/kg (FCEV) and 3.76 USD/kg (H₂-ICE) on a per-kilometer basis, and 3.01 and 3.43 USD/kg respectively on a per-ton-kilometer basis. Table 11 shows that 3.0–3.8 USD/kg is below what is currently achievable even at the plant gate, let alone at the pump. Alternatively, holding the hydrogen price at 7.78 USD/kg and imposing a carbon price on well-to-wheel emissions, parity requires approximately 435 USD/t (FCEV) and 542 USD/t (H₂-ICE), several times current European allowance prices. At a more plausible 100 USD/t, diesel rises to 0.936 USD/km and the FCEV to 1.192: the gap narrows by about a third but does not close.

Monetizing the availability difference as foregone revenue at 0.35 USD/km of gross margin would add approximately 0.03 USD/km to the battery electric case and 0.01 to the hydrogen cases relative to diesel, which does not change any ranking reported above.

8.6. Well-to-Wheel Greenhouse-Gas Emissions

Production-stage carbon intensity differs sharply by pathway. Steam methane reforming yields about 10.4 kg CO₂eq/kg H₂. Grid-based electrolysis on Türkiye's current mix (0.42 kg CO₂eq/kWh, 7.8% network losses) yields about 25.3 kg CO₂eq/kg before compression, more than twice the emissions of unabated reforming. Hybrid-renewable electrolysis falls to 1.6 kg CO₂eq/kg, plus 1.8 kg CO₂eq/kg for grid-supplied compression and dispensing.

Propagating these intensities to a well-to-wheel basis with Equations (13) and (14), within the boundary of Section 2.8, gives a stark result: a hydrogen truck fueled by grid-electrolytic hydrogen emits 2,182 g CO₂eq/km (FCEV) to 2,619 g CO₂eq/km (H₂-ICE), against 1,056 for the diesel baseline, 107% and 148% worse. The same vehicles on hybrid-renewable hydrogen emit 284 and 340 g CO₂eq/km, reductions of 73% and 68%. A battery electric truck on the current grid emits 683 g CO₂eq/km, 35% below diesel, and on renewable supply 42 g CO₂eq/km (Figure 10).

Three points qualify for this result. First, the decisive variable is the electricity source, not the powertrain: the spread within the FCEV row (217 to 2,182 g CO₂eq/km) is an order of magnitude, while the spread between powertrains at a fixed electricity source is under 25%. Second, hydrogen leakage at an assumed 1.5% with GWP₁₀₀ = 11.6 [19] adds 14 g CO₂eq/km to the FCEV and 17 to the H₂-ICE, negligible against grid hydrogen, but about 5% of the renewable-hydrogen total, which is where leakage control matters. Third, and most importantly, these are well-to-wheel figures; the vehicle-cycle emissions excluded by the boundary of Section 2.8 fall disproportionately on the battery electric and fuel-cell options [20], so the advantages shown for those options are upper bounds.

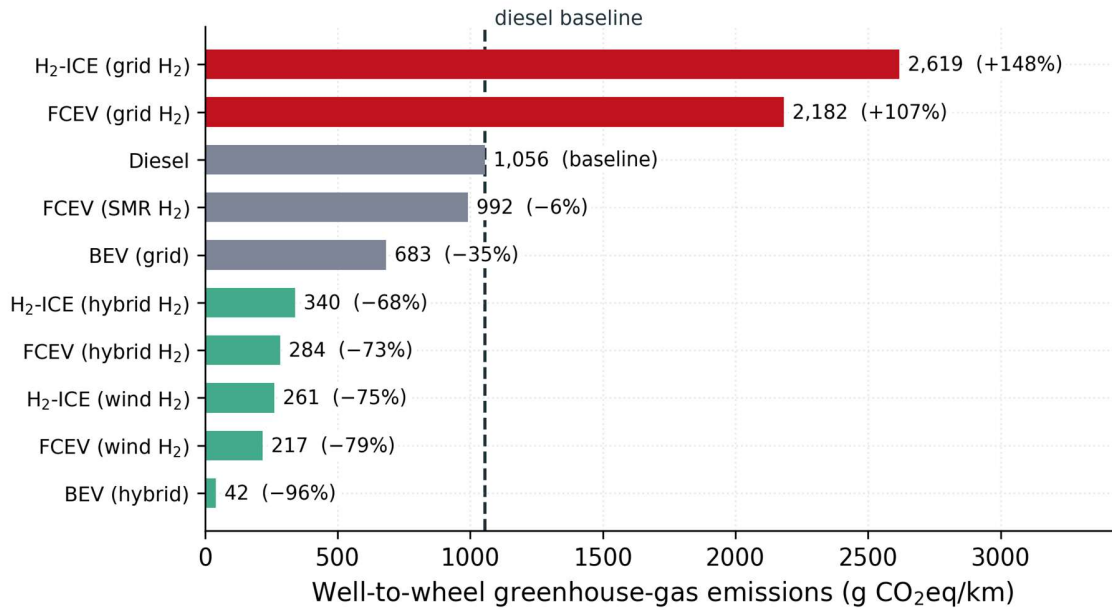


Figure 10. Well-to-wheel greenhouse-gas emissions for a 40 t heavy-duty truck by powertrain and energy source under Turkish conditions. Red bars exceed the diesel baseline (dashed line).

8.7. Uncertainty and Global Sensitivity

Monte-Carlo analysis with the rank-correlated inputs of Table 16 characterizes the uncertainty around the plant-gate point estimate (Figure 11). For hybrid-renewable alkaline production the LCOH distribution is right-skewed with a median of 4.29 USD/kg, a P10–P90 range of 3.59–5.09 and a P5–P95 range of 3.42–5.31. The probability of achieving an LCOH below 4.00 USD/kg is 31%; below 5.00 USD/kg, 87%.

Imposing the correlation structure widens the distribution appreciably: the independent-input P10–P90 range is 3.67–4.98, some 12% narrower. Treating the parameters as independent, as is standard practice, therefore understates the risk. The mechanism is the positive correlation between discount rates and capital cost, which makes adverse financing and adverse equipment pricing coincide.

The sensitivity analysis is summarized in Figure 12, and its principal result is a negative one that is worth reporting for that reason. The one-at-a-time tornado ranks renewable electricity price first, with a swing of 1.95 USD/kg across its range, then electrolyzer capital cost (1.09), specific energy consumption (0.53), real discount rate (0.50), capacity factor (0.25) and fixed O&M (0.24), about a base case of 4.01 USD/kg. The variance-based decomposition reproduces that ranking rather than overturning it. Renewable electricity price carries both the largest first-order index ($S_i = 0.65$) and the largest total-effect index ($S_{Ti} = 0.64$); capital cost follows at 0.22 and 0.23; and the remaining four parameters together account for less than 0.15 of the output variances on either measure. For every parameter the two indices agree to within the sampling error of the estimator.

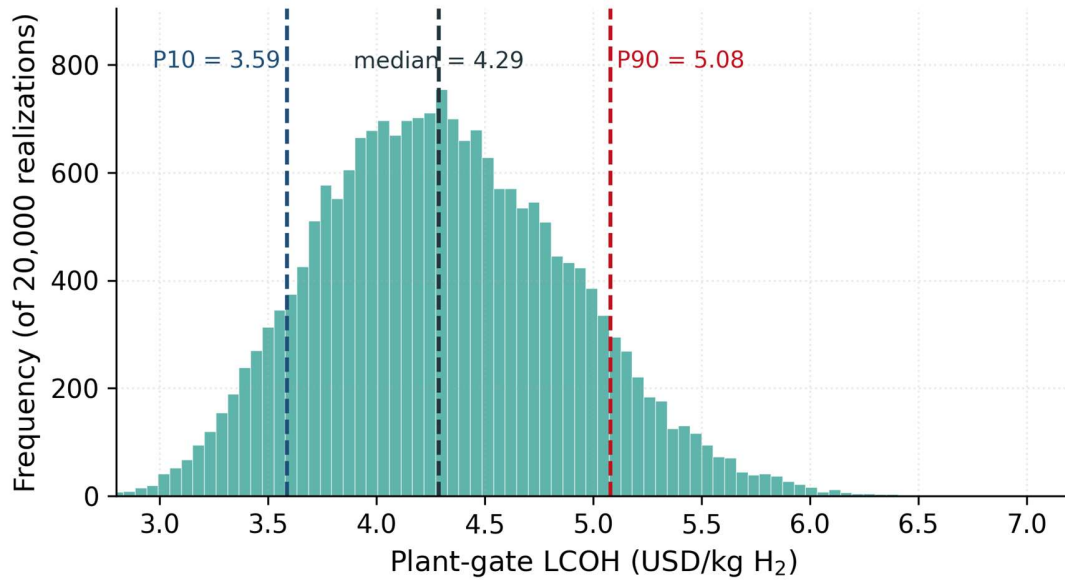


Figure 11. Monte-Carlo distribution of plant-gate LCOH for hybrid-renewable alkaline production (20,000 rank-correlated realizations), with P10, median and P90 marked.

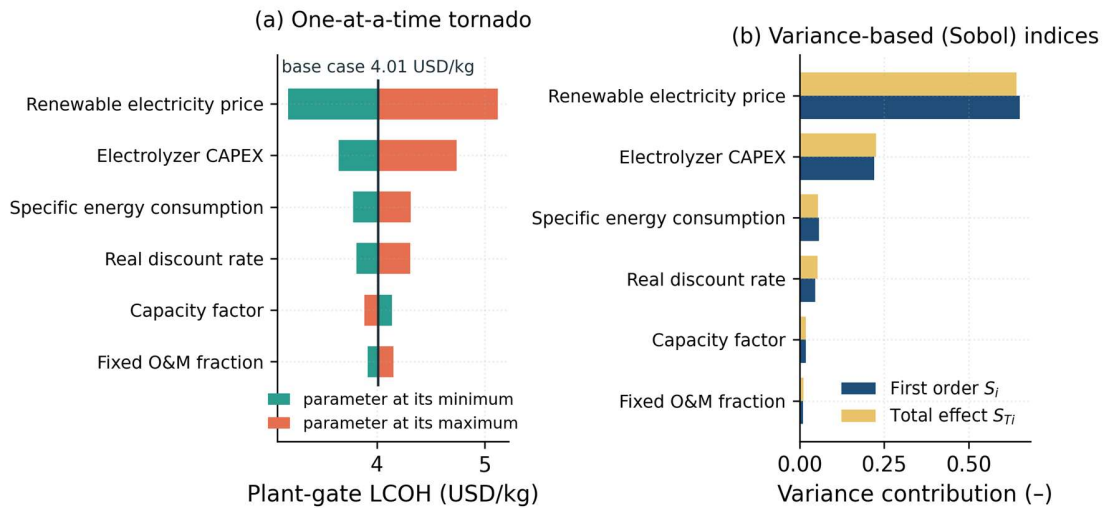


Figure 12. Sensitivity of plant-gate LCOH: (a) one-at-a-time tornado about the base case of 4.01 USD/kg, each parameter varied to the minimum and maximum of Table 16; (b) first-order (S_i) and total-effect (S_{Ti}) Sobol indices from a base sample of 262,144. The near-coincidence of the two indices for every parameter, and the summation of the first-order indices to unity, indicate that the model is close to additive over the ranges sampled, so the tornado ordering in panel (a) is reliable here.

That agreement is itself the finding. The first-order indices sum to 1.00, so the interaction variance, the share of output variance that no parameter explains on its own, is below the resolution of the estimator, on the order of 1–2%. The model is therefore close to additive over the ranges of Table 16. This is a statement about the ranges, not about the functional form: Equation (3) is a sum of terms that are individually products, and the rank correlations of Section 2.9 make electricity price and capacity factor covary, so interactions certainly exist

in the model. They are small here because the sampled intervals are narrow enough that the response is nearly linear within them. Had the capacity-factor range been 0.20–0.60 rather than 0.44–0.55, the interaction terms would not have been negligible, and the additive approximation would have failed. Rank correlations imposed: discount rate–CAPEX +0.35; discount rate–PPA price +0.25; PPA price–capacity factor –0.45; CAPEX–specific energy consumption +0.30; all others zero.

Table 16. Monte-Carlo input distributions (triangular; N = 20,000) and the imposed rank-correlation matrix.

Parameter	Minimum	Mode	Maximum	Source of Range
Alkaline equipment CAPEX (USD/kW)	450	600	900	[21,22]
Renewable PPA price (USD/kWh)	0.030	0.045	0.065	[23]
Specific energy consumption at BoL (kWh/kg)	49	52	56	[21,24]
Electrolyzer capacity factor	0.44	0.50	0.55	Section 8.3 ensemble
Real discount rate	0.07	0.10	0.14	Turkish project financing
Fixed O&M (fraction of CAPEX)	0.020	0.030	0.045	[22]

Two practical conclusions follow, one methodological and one about technology. Methodologically, the one-at-a-time tornado on which the prior techno-economic literature relies almost exclusively is, in this instance, adequate: it delivers the same parameter ordering as the full variance decomposition at a small fraction of the computational cost. That is a useful license for practitioners working on comparable screening problems, but it is a license that could only be issued by performing the variance-based analysis, not by assuming the answer. Reporting a tornado alone leaves the reader unable to distinguish the case where it is reliable from the case where it is not. On the technology, the conclusion is unusually clean: procurement and policy attention should go overwhelmingly to the renewable power purchase price, which alone governs about two-thirds of the uncertainty in plant-gate cost, with capital cost a clear but distant second at roughly one-fifth.

Capacity factor has a small index on both measures (0.018), not because it is unimportant in absolute terms, but because the design optimization of Section 8.3 has already collapsed its plausible range. This is a general feature worth stating: sensitivity indices measure the consequences of *residual* uncertainty, not the importance of a parameter in the underlying physics. A parameter that has been engineered into a narrow band will register as insensitive precisely because engineering has succeeded.

Applying the same stochastic treatment to the vehicle comparison (Figure 13) gives the probability that an FCEV truck undercuts diesel as a function of delivered hydrogen price, propagating uncertainty in diesel price, maintenance cost and annual mileage. The 50% threshold occurs at 3.68 USD/kg on a per-vehicle-kilometer basis and 3.08 USD/kg on a per-payload-ton-kilometer basis. Above 5 USD/kg the probability is below 2% on either basis. Since the derived depot price is 7.78 USD/kg, the probabilistic conclusion is unambiguous under current conditions and consistent with the deterministic result of Section 8.5.

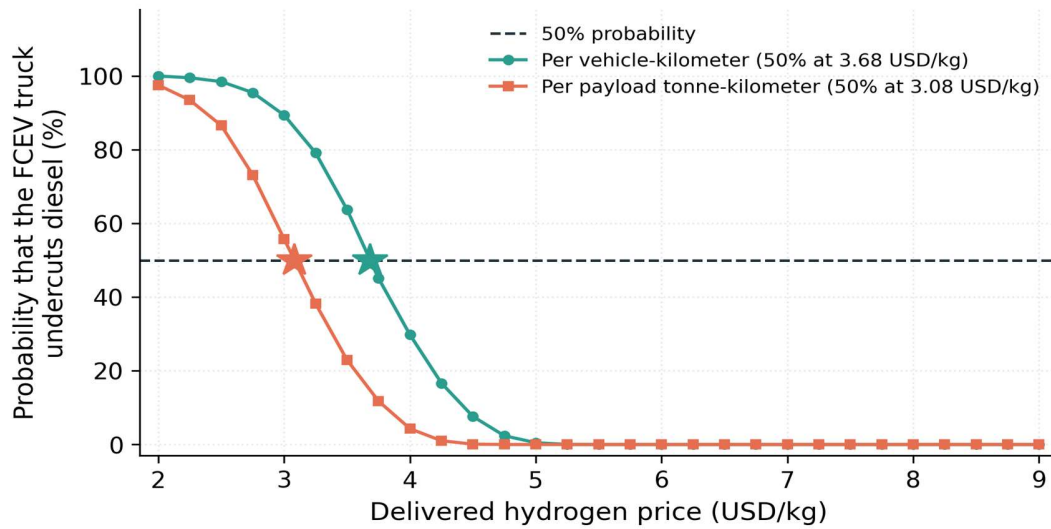


Figure 13. Monte-Carlo probability that the FCEV truck achieves a lower total cost of ownership than diesel, as a function of delivered hydrogen price, on both a per-vehicle-kilometer and a per-payload-ton-kilometer basis. The green and orange star markers indicate the 50% probability thresholds at 3.68 USD/kg (per vehicle-kilometer) and 3.08 USD/kg (per payload ton-kilometer), respectively.

8.8. Long-Term Competitive Dynamics, 2025–2040

The comparison of Section 8.5 is a snapshot of a system in rapid motion, and a conclusion drawn from 2025 costs is not a conclusion about 2040. Table 17 and Figure 14 extend the analysis to 2030, 2035 and 2040 under a single consistent scenario in which battery pack prices continue to fall, electrolyzer capital costs decline along the learning curve of [7], delivered hydrogen falls to 4.20 USD/kg by 2040, the Turkish grid decarbonizes from 0.42 to 0.16 kg CO₂eq/kWh in line with the 2053 net-zero pathway, and diesel prices rise modestly in real terms.

Table 17. Long-term scenario results, levelized cost in USD/km (per payload ton-kilometer in US cent in parentheses).

Year	Delivered H ₂ (USD/kg)	Grid CI (kg CO ₂ eq/kWh)	Diesel	BEV	FCEV	H ₂ -ICE
2025	7.78	0.42	0.830 (3.19)	0.800 (3.56)	1.164 (4.75)	1.216 (4.86)
2030	6.40	0.31	0.852 (3.28)	0.700 (3.11)	0.999 (4.08)	1.068 (4.27)
2035	5.10	0.22	0.875 (3.36)	0.654 (2.91)	0.864 (3.53)	0.935 (3.74)
2040	4.20	0.16	0.900 (3.46)	0.624 (2.77)	0.772 (3.15)	0.843 (3.37)

Three findings emerge. First, the FCEV reaches approximate parity with diesel on a per-kilometer basis by 2035 (0.864 against 0.875 USD/km) and moves clearly below it by 2040 (0.772 against 0.900). The H₂-ICE reaches parity around 2038 and remains the more expensive hydrogen option throughout, because its efficiency disadvantage compounds as fuel remains the dominant cost term. Second, the battery electric truck extends its lead throughout: 0.700 USD/km in 2030 and 0.624 in 2040, and on a per-payload-ton-kilometer basis it overtakes diesel between 2025 and 2030 as pack energy density improves and the payload penalty erodes. Third, grid decarbonization transforms the emissions comparison:

at a grid intensity of 0.16 kg CO₂eq/kWh, grid-based electrolytic hydrogen ceases to be worse than diesel, and the battery electric truck on grid power approaches the emissions of renewable hydrogen.

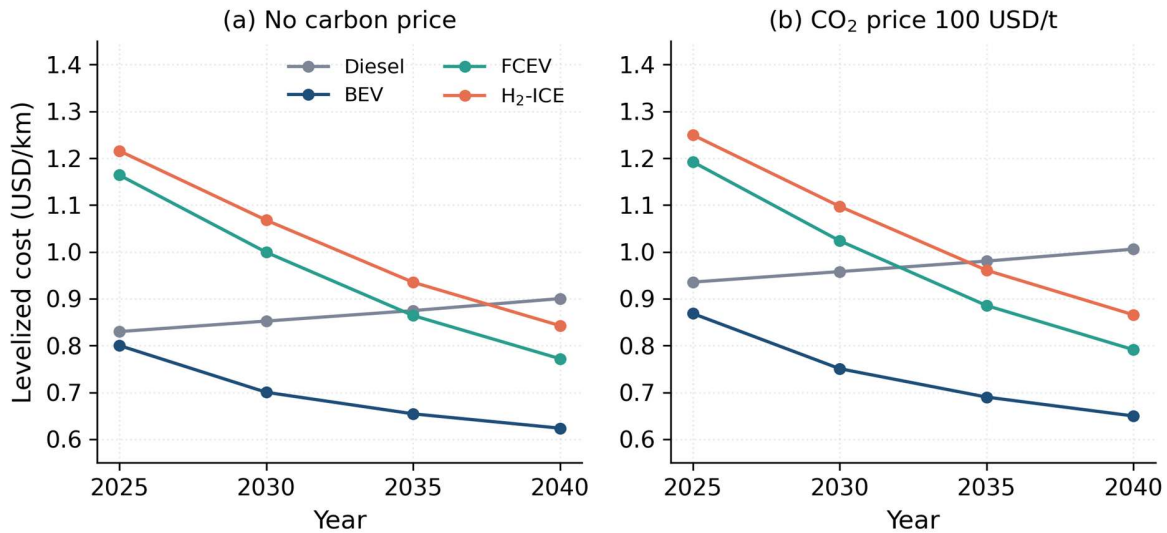


Figure 14. Levelized cost of ownership trajectories, 2025–2040, (a) without and (b) with a CO₂ price of 100 USD/t.

The policy reading is that the window in which hydrogen holds a distinctive advantage in Turkish road freight is bounded on both sides. Before roughly 2030 it is not cost-competitive on any basis. After roughly 2035 the battery electric alternative is improving at least as fast, so hydrogen’s durable niche narrows towards the applications where batteries remain structurally disadvantaged: very long-haul corridors without charging infrastructure, weight-limited bulk haulage, high-utilization multi-shift operations where charging downtime is unaffordable, and off-grid or grid-constrained locations. This qualifies rather than contradicts the deployment argument of Section 8.9, and it is the reason that argument is framed around transitional and niche applications rather than around fleet-wide substitution.

8.9. Synthesis

Taken together the analyses give a prioritization for Türkiye that is more qualified than the one advanced in the submitted version.

- **Economically**, low-cost hydrogen depends on hybrid-renewable, low-capital-cost alkaline production and on reducing financing costs. The dispatch and Monte-Carlo analyses identify the renewable electricity price as the dominant lever by a wide margin, it governs about two-thirds of the variance in plant-gate cost, with capital cost a distant second, and identify a hybrid solar–wind plant oversized by a factor of about 2.5 as the cost-minimizing configuration. But at the delivered price this produces, neither hydrogen powertrain is competitive with diesel today, and the battery electric truck is cheaper than both on either accounting basis.

- **Environmentally**, the same renewable coupling is what turns hydrogen from a carbon liability into a deep-decarbonization option. Grid-based electrolytic hydrogen on the current Turkish mix is worse than diesel by a factor of two. The battery electric truck is the lowest-emission option in every electricity scenario examined.
- **In readiness terms**, alkaline electrolysis and H₂-ICE conversion carry the smallest transfer gaps, at 2.6 and 2.0 levels against 4.2–5.8 for fuel-cell and high-pressure-storage technologies.

These three lenses do not converge on a single recommendation, and it would be misleading to present them as though they did. They converge on renewable-coupled, alkaline-based production, which is supported by all three. They diverge on the powertrain. On cost and emissions, the near-term answer for Turkish road freight is battery electrification wherever duty cycle and payload permit. The case for H₂-ICE is neither a cost case nor an emissions case; it is a case about what a Turkish manufacturer can build, a Turkish workshop can maintain, and a Turkish regulator can approve within five years rather than fifteen.

That case is real but narrow. The defensible applications for H₂-ICE in Türkiye are: (i) duty cycles in which battery mass or charging downtime is prohibitive and where the alternative is continued diesel operation, not electrification; (ii) captive fleets with depot refueling and a co-located renewable hydrogen source, which avoids the retail-station cost and reliability problem quantified in Sections 8.2 and 7.1; (iii) retrofit of existing diesel fleets, where the conversion cost of 20–30% competes against the full replacement cost of a new vehicle; (iv) off-road, port, mining and material-handling equipment, where duty cycles are predictable, refueling is centralized and emission regulation is less stringent; and (v) as a domestic industrial-capability bridge, in which building and maintaining hydrogen engines develops the fuel handling, storage, safety and regulatory competence that later fuel-cell deployment requires.

Each of these is conditional on the NO_x after-treatment requirement of Section 4.3 being met, and none of them is a case for H₂-ICE as a general replacement for diesel or as a competitor to battery electrification on cost.

9. Safety, Public Acceptance and Regulatory Readiness

Neither safety nor public acceptance featured in the submitted version, and both are decisive for the infrastructure and regulation criteria that dominate the transfer gaps of Table 9.

9.1. Hazard Characteristics

Hydrogen's wide flammability range (4–75 vol%), very low minimum ignition energy (0.02 mJ), high diffusivity and inverse Joule–Thomson behavior above ambient temperature give it a hazard profile that is different from, rather than uniformly worse than, that of conventional fuels. Rapid buoyant dispersion reduces pooling risk relative to liquid fuels; high storage pressure and low ignition energy increase jet-fire and vapor-cloud-explosion risk. Quantitative risk assessments of urban refueling stations consistently identify high-pressure pipe and compressor-to-storage connections as the dominant contributors [60].

9.2. Separation Distances and Siting

Risk-based separation distances derived for 350 bar urban stations are substantially larger than those customary for petrol retail, which constrains siting in dense urban fabric and is one reason depot and industrial-zone siting is more tractable in the near term than urban retail [60]. Türkiye has adopted the relevant international standards by reference [57,58] but does not yet have an equivalent national code with established permitting practice and accredited third-party inspection, which is the basis of the regulation score of 5 assigned to refueling stations in Table 9.

9.3. Public Acceptance

Acceptance of hydrogen refueling infrastructure is strongly mediated by perceived safety and by the provision of risk information, and residents living near proposed sites hold systematically different views from the general public [61]. High-profile incidents have measurable effects on acceptance well beyond the affected jurisdiction. For an emerging market beginning deployment, two implications follow: the first stations built will disproportionately shape acceptance, so reliability and incident-free operation matter more at low deployment levels than at high ones; and structured risk communication should be treated as part of the deployment cost, not as an afterthought.

9.4. Workforce and Inspection

Safe operation depends on trained operators, competent maintenance and accredited inspection. This is the same workforce constraint identified in Section 7.3, arriving through a different route, and it reinforces the conclusion that skills development is a precondition rather than a complement to hardware deployment.

10. Limitations

The following limitations qualify the interpretation of these results, and several are material enough to bound the conclusions.

1. **Readiness scoring.** The EMRI criterion scores are assigned by a single author. Weight sensitivity is quantified (Table 9), but score sensitivity is not formally elicited. A structured multi-expert Delphi process with an inter-rater reliability statistic is the appropriate next step, and until it is performed the readiness results should be read as a transparent and falsifiable hypothesis rather than as a measurement. The gap *orderings* are more robust than the gap *magnitudes*.
2. **Renewable profiles.** The 8,760-hour series are synthetic, calibrated to published Turkish capacity factors but not validated against measured or reanalysis data, and statistically stationary. They therefore cannot reproduce anomalous years, spatial correlation across a portfolio of sites, or the persistence of extreme low-generation episodes. The reported interannual LCOH variability (± 0.02 USD/kg) is consequently a lower bound.

3. **Dispatch scope.** The dispatch model is single-node and single-year, with no on-site hydrogen or battery storage, no grid hybridization and no participation in electricity markets. Each of these would reduce the cost of intermittency and would lower the reported LCOH.
4. **Distributional assumptions.** Triangular distributions are a maximum-entropy choice given three-point information, not an empirical finding. The imposed rank correlations are reasoned, not estimated from data.
5. **Emissions boundary.** The analysis is well-to-wheel, not cradle-to-grave. Vehicle, battery, stack, tank and infrastructure manufacturing are excluded, and these exclusions favor the battery electric and fuel-cell options [20]. N₂O from H₂-ICE after-treatment is excluded. Non-greenhouse pollutants are excluded from the metric and discussed separately.
6. **Vehicle parameters.** No hydrogen heavy-duty fleet operates in Türkiye, so vehicle parameters are representative values from European and Chinese deployments rather than Turkish operating data. Cost and emission figures are a 2024–2025 snapshot of a rapidly moving field.
7. **Geographic scope.** Conclusions apply to Türkiye. Section 7.4 indicates which are likely to transfer, and which are not, but that positioning is not a substitute for country-specific analysis.
8. **Future research.** Priorities are, in order: multi-expert elicitation of the readiness scores; substitution of multi-year measured renewable data with spatially resolved siting; co-optimization of on-site hydrogen and battery storage with grid hybridization; extension to a cradle-to-grave inventory including vehicle and tank manufacturing; and integration of carbon-pricing and hydrogen-certification scenarios with the Turkish 2053 net-zero pathway.

11. Conclusions

This integrated assessment yields five findings for hydrogen mobility in Türkiye and, with the qualifications of Section 7.4, for comparable emerging markets.

First, global technology maturity is a poor guide to what an emerging market can deploy. Under the scored dual-readiness framework of Section 2.3, transfer gaps range from 2.0 levels for H₂-ICE conversion and 2.6 for large alkaline electrolysis to 4.2–5.8 levels for FCEVs, 700 bar storage and fuel-cell stack manufacturing. These orderings are robust to the weighting of the readiness criteria; the absolute magnitudes are not yet expert-validated.

Second, the distinction between production cost and delivered price is decisive and is frequently elided. Plant-gate LCOH for hybrid-renewable alkaline production is 4.11 USD/kg by annual-average accounting and 4.14 USD/kg under hourly dispatch at the optimal oversizing ratio of about 2.5, with a Monte-Carlo median of 4.29 (P10–P90: 3.59–5.09). Delivering that hydrogen to a captive depot dispenser costs a further 3.64 USD/kg, giving 7.78 USD/kg; delivering it through a public retail station costs a further 8.77, giving 12.91.

Third, at those prices hydrogen road freight is not competitive in Türkiye today. Diesel costs 0.830 USD/km against 1.164 (FCEV) and 1.216 (H₂-ICE). Parity requires delivered hydrogen at 3.0–3.8 USD/kg, or a carbon price above 435 USD/t. The battery electric truck is the cheapest option per vehicle-kilometer but, once the payload penalty is applied, is 12% more expensive than diesel per payload ton-kilometer, a distinction that reporting only per-kilometer costs conceals.

Fourth, the electricity source, not the powertrain, governs the climate outcome. Grid-based electrolysis on the current Turkish mix produces well-to-wheel emissions of 2,182–2,619 g CO₂eq/km, more than twice the diesel baseline of 1,056; hybrid-renewable hydrogen cuts them by 68–73%. These are well-to-wheel figures, and the excluded vehicle-cycle emissions fall disproportionately on the zero-tailpipe options.

Fifth, the recommendation that follows is narrower than technology endorsement. Renewable-coupled alkaline electrolysis is supported by all three lenses and should be the priority production investment. For the powertrain, cost and emissions favor battery electrification wherever duty cycle and payload permit, and the case for H₂-ICE rests specifically on near-term deployability, a two-level transfer gap against four to six, rather than on operating economics, in which it is the weakest of the four options examined. Its defensible applications are the transitional and niche cases enumerated in Section 8.9, each conditional on meeting the NO_x after-treatment requirements of Section 4.3. Higher-gap systems, FCEVs, 700 bar storage, stack manufacturing, warrant sustained investment for long-term competitiveness, supported by dedicated renewable supply, lower financing costs, a carbon-pricing signal and systematic workforce development, and tailored to the resource endowment and manufacturing capability of each market [7–9,37].

Nomenclature

Symbol	Definition	Unit
A_{stack}	Annualized stack replacement cost	USD/kW.yr
C_0	Vehicle purchase price	USD
$C_{\text{eq}}, C_{\text{inst}}$	Electrolyzer equipment, installed capital cost	USD/kW
CF	Capacity factor	–
CI_e, CI_{grid}	Carbon intensity of supply, of grid electricity	kg CO ₂ eq/kWh
CRF	Capital recovery factor	1/yr
c_f, c_m, c_c	Fuel, maintenance, carbon cost per kilometer	USD/km
e_{WTW}	Well-to-wheel emissions	g CO ₂ eq/km
g_t, x_t	Available, absorbed power in hour t	p.u. of rating
i, N, N_v	Real discount rate; plant, vehicle life	–, yr, yr
L	Annual mileage	Km/yr
$\dot{m}_a$	Annual hydrogen yield per unit rated power	Kg/kW.yr
m_{pay}	Payload	T
$P_e, P_{\text{del}}, P_{\text{CO}_2}$	Electricity price, delivered H ₂ price, carbon price	USD/kWh, USD/kg, USD/t
q_{100}, q_{cdl}	Energy use per 100 km; compression/dispensing energy	L, kWh or kg; kWh/kg
r	Renewable oversizing ratio	–
S_i, S_{Ti}	First-order, total-effect Sobol index	–
s_{ij}, w_j	EMRI criterion score, weight	–

Symbol	Definition	Unit
SEC	Specific energy consumption	kWh/kg
α, β, δ	Auxiliary fraction, stack cost fraction, degradation rate	–, –, per 1,000 h
Δ_i	Technology-transfer gap	TRL levels
$\kappa, \lambda, \phi, \rho$	Installation factor, network losses, H ₂ leakage, residual fraction	–

Supplementary Material

Supplementary File S1: Python source code of the complete computational model (a single documented module of approximately 550 lines) implementing the plant-gate levelized cost of hydrogen, the plant-gate-to-dispenser delivery chain, the hourly renewable dispatch with electrolyzer operating constraints, the total cost of ownership on an equivalent transport-service basis, the well-to-wheel greenhouse-gas assessment, the Monte-Carlo and Sobol sensitivity analyses, and the Emerging-Market Readiness Index scoring (Sections 2.3–2.9).

Supplementary File S2: Python script that executes the model of Supplementary File S1 with the parameters of Table 5 and regenerates every figure and numerical result reported in this paper; random number generation is seeded, so all results are bit-reproducible.

Author Contributions

Kadir Aydın: conceptualization, methodology, software, formal analysis, investigation, data curation, visualization, writing original draft, review and editing. The author has read and agreed to the published version of the manuscript.

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Conflict of Interest

The author declares no conflict of interest.

Ethics Approval Statement

Not applicable. This study did not involve human participants or animals.

Data and Code Availability Statement

All model parameters are given in Tables 5, 15 and 16. The complete computational model (LCOH, delivery chain, hourly dispatch, TCO, well-to-wheel emissions, Monte-Carlo and Sobol

estimation, and EMRI scoring) and the figure-generation script are provided as Supplementary Files S1 and S2 and reproduce every numerical result and figure in this paper. Random number generation is seeded, so results are bit-reproducible.

Declaration of the Use of Generative AI and AI-Assisted Technologies

During the preparation of this work the author used a large language model (Anthropic Claude) for three purposes: implementing and debugging the Python code that produces the levelized-cost, dispatch, ownership-cost, well-to-wheel and sensitivity results and that generates the figures; drafting and restructuring the manuscript; and language and consistency editing. The tool was not used to generate data, and no result reported here originates from the model rather than from the computation. All modeling assumptions, parameter values and their sources were specified by the author; every numerical value was checked against the supplied source code; every reference was verified against its DOI or publisher record; and the author reviewed and edited all AI-assisted output. The author takes full responsibility for the content of this publication.

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