Techno-Economic Viability of Clean Hydrogen Under 45V Compliance: A Decision-Grade Parity Framework

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Abstract

Clean hydrogen's commercial viability hinges on Section 45V tax credits, yet compliance constraints may fundamentally alter cost parity assumptions. This study presents a decision-grade parity mapping framework that treats viability as an operationally constrained screening problem rather than an unconstrained cost-screening exercise, as a screening-resolution complement to dispatch-resolved techno-economic studies.

Using a representative U.S. case with central parity benchmark \$1.70/kg, the modeled long-run hourly baseline (\$67/MWh, $\phi = 0.50$) yields gross LCOH of \$5.04/kg and Net LCOH of \$2.04/kg, which is \$0.34/kg above parity. The framework quantifies viability contraction under compliance-constrained operation, identifies threshold conditions where small utilization or credit-tier changes trigger large Net LCOH jumps, and separates geometric viability from market-weighted viability. Results indicate that parity under realistic 45V-compliant operation is narrow and fragile, with electricity procurement and credit continuity as first-order drivers of bankability. These conclusions are benchmark-conditional: baseline operation is above parity at \$1.70/kg but reaches parity at higher benchmark levels (for example, \$2.50/kg). Although the framework is developed for hydrogen, its structure is designed to be transferable to other subsidy-dependent clean infrastructure systems.

Keywords: Clean hydrogen, 45V tax credit, cost parity, electrolyzer utilization, policy-induced discontinuities, techno-economic analysis

Nomenclature

Symbol	Definition
ϕ	Electrolyzer capacity factor (annual operating fraction).
p_e	Effective delivered electricity price (\$/MWh).
A	Capital-cost coefficient (\$/kg per unit capacity factor).
C_{cap}	Installed electrolyzer capital cost (\$/kW).
CRF	Capital recovery factor.
E_{req}	Electricity requirement (kWh/kg H_2).
C_{OPEX}	Non-electric operating expenditure (\$/kg H_2).
C_{credit}	Applicable 45V production credit (\$/kg H_2).
κ	Capital-intensity ratio (capital-to-electricity cost exposure, dimensionless).
Ψ_{credit}	Credit-dependency ratio ($C_{\text{credit}}/\text{LCOH}_{\text{gross}}$, dimensionless).
Γ_{geom}	Geometric viable-fraction metric over modeled design space.
Γ_w	Market-weighted viable-fraction metric using empirical (p_e, ϕ) distributions.
$P_{\text{benchmark}}$	Gray-hydrogen parity benchmark (\$/kg H_2).

1. Introduction

Clean hydrogen from water electrolysis is a priority pathway for decarbonizing steel, chemicals, and long-duration energy systems [1, 2]. At the same time, global hydrogen supply remains mostly fossil-based, and electrolytic hydrogen remains above gray-hydrogen cost in many regions [1, 3].

Section 45V changed project economics by introducing a production tax credit of up to $3/kg for low-emissions hydrogen [4]. In practice, however, project economics depend on operational compliance with additionality, deliverability, and temporal matching requirements. These constraints can reduce achievable capacity factor and change credit-tier eligibility in ways that create discrete cost shifts [5, 6].

This study addresses a practical investment question: under realistic 45V-compliant operation, where does parity remain feasible? The paper focuses on parity as an operationally constrained feasibility problem rather than an unconstrained cost-minimization problem. This framing is directly aligned with project screening, financing, and siting decisions.

Most conventional techno-economic analyses are useful for benchmarking but often assume fixed electricity price and fixed high utilization [3]. Those assumptions can overstate deployable parity when hourly matching and deliverability constraints bind. Dispatch-resolved studies already address this at higher fidelity by modeling operational constraints with time-series inputs [7–9]; this paper complements that literature with a screening-resolution algebraic mapping approach for fast parity diagnostics.

This study presents a decision-grade parity mapping framework in electricity-price and capacity-factor space. Here, "decision-grade" denotes project-screening outputs that explicitly incorporate operationally constrained capacity factors, tiered credit eligibility, and threshold conditions relevant to go/no-go bankability decisions. The analysis quantifies viability contraction from annual to hourly matching windows, identifies threshold conditions where small operational changes create large Net LCOH shifts, and separates geometric viability from market-weighted viability. The objective is to provide a structured parity assessment for developers, lenders, and policymakers.

2. Background: Cost Parity and 45V Policy Constraints

2.1. Hydrogen Cost Parity: Conventional Framing

Cost parity between clean (green) hydrogen and gray hydrogen is conventionally defined as the electricity price at which the levelized cost of hydrogen (LCOH) from electrolysis equals the prevailing cost of hydrogen from steam methane reforming (SMR), typically in the low single-dollar-per-kilogram range depending on natural gas prices and regional conditions [1, 3, 10].

While gray hydrogen pricing varies regionally ($1.00–$2.50/kg), we adopt $1.70/kg as the reference benchmark for all quantitative comparisons unless otherwise stated, representing U.S. Gulf Coast conditions. Regional benchmark sensitivities at $1.00/kg (low-cost gas regions) and $2.50/kg (higher-cost import-dependent regions) are reported explicitly so benchmark selection remains transparent.

Standard parity analyses parameterize LCOH as a function of:

- Delivered electricity price ($/MWh)
- Electrolyzer capital expenditure ($/kW)
- System efficiency (kWh/kg H_2)

- Capacity factor
- Operations and maintenance costs

These models typically assume high capacity factors for continuous or near-continuous operation, which materially improves parity outcomes relative to intermittency-constrained operation [3, 11]. Recent Applied Energy studies using meteorological and hybrid-supply dispatch contexts report materially lower effective capacity factors once curtailment and matching constraints are included, reinforcing the utilization-risk channel highlighted here [7–9].

Recent policy and market studies also show widening regional divergence in parity conditions. European policy packages (EU Hydrogen Strategy and REPowerEU), together with implementation vehicles such as the European Hydrogen Bank, prioritize rapid scale-up but operate under relatively higher delivered energy and infrastructure costs [12–16]. By contrast, resource-rich export corridors in MENA and Australia are frequently modeled with lower long-run renewable input costs, albeit with transmission, water, and logistics constraints that affect delivered hydrogen economics [17–20].

Learning-curve evidence further reinforces that parity trajectories are path-dependent rather than universal: one- and two-factor electrolysis learning models indicate substantial cost decline potential from deployment scale, manufacturing maturity, and electricity-price context, but with persistent uncertainty in the pace and regional transferability of those gains [21–23]. Recent Applied Energy case studies across steelmaking, large-scale storage-coupled systems, and export chains similarly identify delivered electricity and achievable utilization as dominant drivers in practical deployment contexts [9, 19, 20, 24].

2.2. Section 45V: Structure and Compliance Requirements

The 45V production tax credit provides up to $3.00/kg for hydrogen produced with very low lifecycle emissions intensity, with credit value structured in tiers by emissions performance [4, 5].

Key compliance pillars include:

1. **Temporal matching**: Electricity consumption must be matched with clean energy generation over the required accounting interval.
2. **Deliverability**: Clean energy must be generated within the same region or electrically connected area as the electrolyzer.

3. **Additionality**: Clean energy sources must represent new capacity rather than existing generation.

These implementation constraints and their economic implications are discussed in detail in recent 45V analyses, including proposed-rule and final-rule treatments of emissions accounting and crediting architecture [5, 6, 25–28].

2.3. Utilization Risk Under Policy Constraints

The interaction of temporal matching with variable renewable energy (VRE) generation profiles creates a fundamental tension: electrolyzers paired with wind or solar resources cannot operate continuously while maintaining strict compliance. In practice, achievable capacity factor under hourly-aligned operation can be materially lower than unconstrained grid-enabled assumptions [5–8, 11].

This capacity-factor haircut directly increases the effective capital recovery burden per kilogram of hydrogen produced, potentially invalidating parity conditions that hold under high-utilization assumptions [3, 11].

3. Methodology: Decision-Grade Parity Mapping Framework

3.1. Levelized Cost Model Framework

This study uses a simplified analytical techno-economic model to calculate levelized cost of hydrogen (LCOH) and assess parity against gray-hydrogen benchmarks under Section 45V production tax credit scenarios. The model follows standard discounted cash-flow structure adapted for renewable-powered electrolysis, with explicit treatment of capacity-factor constraints imposed by temporal-matching compliance. The framework is intentionally screening-resolution: hourly-compliance effects are represented parametrically through constrained capacity-factor and credit-tier spaces, rather than through endogenous hourly dispatch simulation.

3.1.1. Core Cost Equation

The levelized cost of hydrogen (gross, pre-credit) decomposes into three components:

$$\mathrm{LCOH} = \frac{A}{\phi} + \left(\frac{p_e}{1000}\right) E_{\mathrm{req}} + C_{\mathrm{OPEX}} \tag{1}$$

where:

- A = capital cost coefficient (\$/kg per unit capacity factor)
- ϕ = electrolyzer capacity factor (dimensionless, 0–1)
- p_e = effective delivered electricity price (\$/MWh)
- E_{req} = electrolyzer electricity requirement (kWh/kg H_2)
- C_{OPEX} = non-electric operating expenditure (\$/kg H_2)

Throughout this paper, capacity factor ϕ and utilization are used interchangeably as the annualized operating fraction of the electrolyzer.

The capital coefficient A captures annualized capital recovery distributed over hydrogen production:

$$A = \frac{C_{\text{cap}} \times \text{CRF} \times E_{\text{req}}}{8760} \tag{2}$$

where C_{cap} is electrolyzer installed capital cost (\$/kW) and CRF is the capital recovery factor:

$$\text{CRF} = \frac{r(1+r)^n}{(1+r)^n - 1} \tag{3}$$

with r = weighted average cost of capital (WACC) and n = project economic lifetime (years). For baseline parameters (7% WACC, 30-year life), CRF = 0.0806.

Net LCOH after applying Section 45V production tax credit:

$$\text{Net LCOH} = \text{LCOH} - C_{\text{credit}} \tag{4}$$

where C_{credit} is the applicable 45V credit tier (\$/kg H_2): Tier 1 = \$3.00/kg for lifecycle emissions <0.45 kg CO_2e/kg H_2, Tier 2 = \$1.00/kg for 0.45–1.5 kg CO_2e/kg H_2, Tier 3 = \$0.60/kg for 1.5–2.5 kg CO_2e/kg H_2. Analysis assumes Tier 1 credit unless otherwise noted.[1]

[1] Section 45V applicable amounts are inflation-adjusted annually by IRS notice; this screening framework uses statutory nominal tier values for transparent cross-scenario comparability [29, 30].

3.1.2. Parameter Selection and Justification

Table 1 summarizes baseline parameter values and ranges explored in sensitivity analysis. Parameters reflect realistic 2025 technology and market conditions for PEM electrolysis coupled with hybrid renewable electricity generation under 45V hourly temporal matching compliance.

Table 1: Baseline techno-economic parameters and sensitivity ranges

Parameter	Symbol	Baseline	Range	Source/Justification
Capital and Financing				
Electrolyzer capital cost	C_{cap}	\$800/kW	600–1200	Representative 2025 PEM installed-cost range (stack, BOP, installation).
WACC	r	7%	5–11%	Utility-scale project finance range from contracted to merchant structures.
Economic lifetime	n	30 years	20–40	Infrastructure lifetime assumption for long-duration hydrogen assets.
Capital recovery factor	CRF	0.0806	0.058–0.125	Computed from WACC and lifetime assumptions.
Electrolyzer Performance				
Electricity requirement	E_{req}	55 kWh/kg	50–58	System-level PEM electricity use including auxiliary loads.
Capacity factor	ϕ	0.50	0.35–0.95	Hourly-compliant operation supports lower CF; annual-matching transition can support higher CF.
Electricity and Operating Costs				
Delivered electricity	p_e	\$67/MWh	20–100	Effective delivered price includes losses, firming, and compliance-aligned procurement effects.
Non-electric OPEX	C_{OPEX}	\$0.548/kg	0.40–0.70	Water, maintenance, labor, insurance/taxes, and stack-life assumptions.
Policy and Benchmarks				
45V tax credit	C_{credit}	\$3.00/kg	0–3.00	Tiered 45V credit; baseline assumes Tier 1 eligibility.
Gray H_2 benchmark	$P_{\text{benchmark}}$	\$1.70/kg	1.00–2.80	U.S. Gulf Coast benchmark with regional comparison bounds.

Key parameter notes:

- **Capital cost (\$800/kW):** Mid-range estimate reflecting 2025 market conditions. NREL's 2024 manufacturing cost analysis projects \$700/kW for high-volume production (1+ GW/year), while 2023 market pricing averaged \$900–1000/kW. Our baseline accounts for current supply chain constraints and installation complexity for first-generation commercial projects. Even when installed costs move to the high side of the tested range, Section 4 shows capex remains second-order relative to delivered electricity in this framework because κ stays in the electricity-dominated regime.

- **Efficiency (55 kWh/kg):** Field-demonstrated system efficiency including compression, cooling, and control auxiliaries. More conservative than stack-level manufacturer targets (52 kWh/kg, 66% HHV) which exclude balance-of-plant parasitic loads. Matches industry operator reports of sustained multi-year performance with periodic degradation.

- **Effective delivered electricity ($67/MWh):** Critical distinction from nominal PPA pricing. A representative decomposition is: $55/MWh contracted renewable energy, +$4.4/MWh transmission and distribution losses (about 8%), +$5.0/MWh firming/backup to maintain minimum electrolyzer load during intermittency, and +$2.6/MWh ancillary and balancing services required for hourly temporal matching compliance, totaling $67/MWh. The 22% premium over nominal PPA pricing represents real-world complications of procuring carbon-eligible electricity rather than unencumbered industrial power contracts. In the baseline, limited 2–4 hour balancing storage is internalized in this delivered-electricity premium; Scenario 7 reports a higher-storage long-run case separately.

- **Capacity factor (0.50 baseline):** Achievable with hybrid wind-solar generation (60% wind, 40% solar capacity mix) plus 2–4 hours of battery storage under 45V hourly temporal matching requirements. Higher CF (0.70–0.95) requires grid backup, which violates emissions accounting for Tier 1 credit eligibility from 2030 onward. Lower CF (0.35–0.45) reflects wind-only or solar-only generation with minimal storage, increasing capital burden through hyperbolic A/ϕ term.

- **Gray hydrogen benchmark ($1.70/kg):** U.S. Gulf Coast steam methane reforming baseline representing regional parity target. Significantly lower than European ($2.50–2.80/kg with high LNG prices) or Japanese benchmarks ($2.80+/kg), but higher than Middle Eastern production ($1.00–1.20/kg with cheap natural gas). Choice of benchmark critically influences parity assessment; we adopt U.S. Gulf Coast as representative for domestic deployment analysis.

3.1.3. *Modeled Case Summary*

This study evaluates a representative U.S. Gulf Coast parity case using a central benchmark of \$1.70/kg with explicit sensitivity at \$1.00/kg and \$2.50/kg. The modeled baseline point is:

- Delivered electricity price: \$67/MWh
- Electrolyzer capacity factor: $\phi = 0.50$
- Electrolyzer capital cost: \$800/kW
- Electrolyzer electricity requirement: 55 kWh/kg H_2
- Non-electric OPEX: \$0.548/kg
- Credit assumption for baseline: Tier 1 (\$3.00/kg)

The baseline parameter set ($\phi = 0.50$, $p_e = \$67/\text{MWh}$, $C_{\text{cap}} = \$800/\text{kW}$, $E_{\text{req}} = 55$ kWh/kg) yields:

$$\begin{aligned}
A &= \frac{800 \times 0.0806 \times 55}{8760} = 0.4048\,\$/\text{kg per unit } \phi \\
\text{LCOH}_{\text{gross}} &= \frac{0.4048}{0.50} + \frac{67}{1000} \times 55 + 0.548 \\
&= 0.810 + 3.685 + 0.548 = 5.04\,\$/\text{kg} \\
\text{Net LCOH} &= 5.04 - 3.00 = 2.04\,\$/\text{kg}
\end{aligned}$$

This baseline Net LCOH of \$2.04/kg lies \$0.34/kg above the benchmark (representing a 20% gap relative to the \$1.70/kg target), indicating green hydrogen remains marginally above parity even with full Tier 1 credit under realistic 45V-compliant operating conditions.

3.2. *Fragility Metrics: Capital Intensity and Credit Dependency*

To quantify economic fragility and identify dominant cost drivers, we define two complementary dimensionless diagnostic ratios characterizing system sensitivity to capital costs versus operating costs, and technology economics versus policy support.

3.2.1. *Capital Intensity Ratio (κ)*

The capital intensity ratio measures the relative contribution of annualized capital recovery to electricity costs:

$$\kappa = \frac{C_{\text{cap}} \times \text{CRF}}{\left(\frac{p_e}{1000}\right) \times \phi \times 8760} \tag{5}$$

This ratio indicates the economic regime:

- $\kappa > 0.60$: **Capital-intensive** regime where capital recovery dominates LCOH. Optimization prioritizes capital cost reduction, utilization maximization, and financing cost minimization. Sensitivity to electricity price is secondary. Examples: early-stage solar PV (2000s, $\kappa \approx 3$–5), current nuclear power ($\kappa \approx 2$–4).

- $0.30 < \kappa < 0.60$: **Balanced** regime where capital and electricity contribute comparably. Optimization requires simultaneous attention to both capital cost and electricity costs. Technology and site selection are equally important.

- $\kappa < 0.30$: **Electricity-dominated** regime where electricity costs dominate LCOH. Optimization prioritizes electricity procurement, site selection for renewable resources, and efficiency improvements. Capital cost reduction provides diminishing returns. Examples: mature solar PV (2020s, $\kappa \approx 0.10$–0.20), aluminum smelting ($\kappa \approx 0.05$–0.15).

For the baseline scenario (C_{cap} = \$800/kW, CRF=0.0806, p_e = \$67/MWh, $\phi = 0.50$):

$$\kappa_{\text{baseline}} = \frac{800 \times 0.0806}{(67/1000) \times 0.50 \times 8760} = \frac{64.48}{293.58} = 0.22 \tag{6}$$

This indicates **electricity-dominated** economics: electricity costs contribute 73% of gross LCOH (\$3.69/kg of \$5.04/kg) while capital recovery contributes only 16% (\$0.81/kg).[2] The low κ indicates strong electricity dominance (about 4.6× electricity-vs-capital contribution at baseline), while the one-at-a-time sensitivity ranking later in Section 4 shows about 3.4× greater leverage for electricity-price improvements versus capital-cost reductions.

[2]These percentage shares are fractions of total gross LCOH (including non-electric OPEX), while κ isolates the capital-to-electricity ratio by construction.

This contrasts with traditional hydrogen roadmaps prioritizing electrolyzer capital-cost targets.

The κ framework enables systematic comparison across scenarios: Tables 3 and 4 present κ values spanning 0.12 (grid-enabled high-CF operation with mid-range electricity) to 0.46 (renewables-constrained low-CF with cheap electricity), demonstrating that no realistic 45V-compliant scenario achieves capital-intensive regime ($\kappa > 0.60$) under current technology and electricity market conditions.

3.2.2. Credit-Dependency Ratio (Ψ_{credit})

Complementing capital intensity, we introduce the **credit-dependency ratio** to quantify reliance on policy support:

Definition 1 (Credit-Dependency Ratio)**.** *The credit-dependency ratio Ψ_{credit} measures the fraction of gross production cost offset by production tax credits:*

$$\Psi_{credit} = \frac{C_{credit}}{LCOH_{gross}} \tag{7}$$

where C_{credit} is the Section 45V production tax credit (\$/kg H_2) and $LCOH_{gross}$ is pre-credit hydrogen production cost.

Throughout this paper, "LCOH" refers to gross production cost before credit application, while "Net LCOH" denotes post-credit cost. The credit-dependency ratio Ψ_{credit} is always calculated using gross LCOH to maintain consistency across scenarios regardless of credit tier. A clarification on terminology: when we discuss "parity," we compare Net LCOH (post-credit) to the gray hydrogen benchmark; when we discuss Ψ_{credit}, we reference the gross LCOH to quantify what fraction of production economics depends on policy support.

The Ψ_{credit} metric captures policy-induced fragility distinct from capital intensity:

- $\Psi_{\text{credit}} < 0.30$: **Low credit dependency**. Technology approaches economic competitiveness independent of subsidies. Subsidy removal causes manageable cost increase (<40%). Policy provides deployment acceleration but is not economically essential.

- $0.30 < \Psi_{\text{credit}} < 0.50$: **Moderate credit dependency**. Technology requires sustained policy support for market competitiveness but can plausibly ”graduate” from subsidies through learning curves and cost reductions. Post-subsidy cost increases (40–100%) are significant but potentially bridgeable.

- $\Psi_{\text{credit}} > 0.50$: **High credit dependency**. Subsidies exceed half of production cost. Technology faces structural economic challenges requiring either: (1) durable policy support, (2) step-change reductions in key input costs (e.g., electricity, feedstocks), or (3) acceptance of higher end-use costs justified by externality benefits. Post-subsidy cost increases (>100%) create cliff dynamics where subsidy expiration may strand assets.

For the baseline scenario ($\text{LCOH}_{\text{gross}} = \$5.04$/kg, $C_{\text{credit}} = \$3.00$/kg):

$$\Psi_{\text{credit,baseline}} = \frac{3.00}{5.04} = 0.59 \tag{8}$$

This high dependency indicates green hydrogen occupies a distinctive economic regime: **electricity-dominated** ($\kappa = 0.22$) yet **credit-dependent** ($\Psi_{\text{credit}} = 0.59$). The dual fragility metrics (κ and Ψ_{credit}) indicate two independent collapse modes:

1. **Electricity cost escalation:** Despite low capital intensity, projects remain vulnerable to electricity price increases. A \$10/MWh delivered electricity increase (15% of baseline) produces \$0.55/kg cost escalation (11% of gross LCOH), potentially eliminating parity margin.
2. **Credit eligibility loss:** Binary policy thresholds create discontinuous cost cliffs. Tier 1 (\$3.00/kg) to Tier 2 (\$1.00/kg) credit reduction imposes \$2.00/kg penalty (40% of gross LCOH) from marginal emissions exceedances, a policy-induced fragility unrelated to technology or market fundamentals.

The κ-Ψ_{credit} metric pair can be used as an organizing lens beyond hydrogen for subsidy-dependent clean-energy technologies. Examples from SAF and mature solar PV are illustrative only in this study; cross-technology values are not estimated from a unified model here.

3.3. Scenario Design and Sensitivity Analysis

To avoid mixing non-equivalent compliance regimes, we model two explicit Section 45V policy windows:

1. **Transition window (2025–2029):** annual temporal matching is permitted.
2. **Long-run compliance window (2030 onward):** hourly temporal matching is required.

Accordingly, Annual-matching scenarios are treated as transition-period cases (or counterfactual benchmarks), not persistent post-2030 operating modes. Final 45V regulations include limited flexibility pathways (including transition-year annual accounting and specified emissions-accounting options), so strict hourly-matching envelopes should be interpreted as conservative screening bounds. In practice, these flexibilities could modestly raise achievable long-run utilization above the $\phi = 0.65$ upper case for some projects and slightly expand $\Gamma_{\mathrm{geom,hourly}}$, without changing the qualitative ranking of dominant cost drivers [26, 27].

This study evaluates seven scenarios spanning the (capacity factor, electricity price) design space:

1. **Annual, high CF, low electricity (transition):** $\phi = 0.90$, \$30/MWh.
2. **Annual, high CF, mid electricity (transition):** $\phi = 0.90$, \$50/MWh.
3. **Hourly, mid CF, low electricity (long-run):** $\phi = 0.45$, \$30/MWh.
4. **Hourly, mid CF, mid electricity (long-run baseline):** $\phi = 0.50$, \$67/MWh effective delivered.
5. **Hourly, low CF, low electricity (long-run):** $\phi = 0.35$, \$30/MWh.
6. **Hourly, low CF, mid electricity (long-run):** $\phi = 0.35$, \$50/MWh.
7. **Hourly + storage (long-run):** $\phi = 0.65$, \$55/MWh.

For each scenario, this study calculates gross LCOH, Net LCOH, parity gap, κ, and Ψ_{credit}. Gross LCOH is the pre-credit levelized cost from Equation 1; Net LCOH is the post-credit levelized cost from Equation 4. The model outputs are annualized levelized costs, not short-run marginal costs.

3.3.1. Computational Workflow and Transparency

Table 2 summarizes how figures and scenario outputs are generated.

Net LCOH uses the credit assumption associated with each scenario definition; annual-transition cases and long-run hourly cases are reported separately to preserve comparability.

Parameter sensitivity analysis employs tornado-style perturbations:

Table 2: Computational workflow and output definitions

Element	Implementation in this study
Primary cost metric	Gross LCOH and Net LCOH (levelized annualized costs). No in-model marginal dispatch optimization.
Temporal resolution	Annualized techno-economic model. Hourly operations are not simulated endogenously at time-step resolution.
Representation of hourly compliance	Hourly/annual matching rules are mapped to feasible capacity-factor ranges and delivered-electricity assumptions by scenario.
Credit treatment	Exogenous credit tiers by scenario (Tier 1 = \$3.00/kg, Tier 2 = \$1.00/kg, Tier 3 = \$0.60/kg, and no-credit sensitivity).
Benchmark treatment	Central benchmark = \$1.70/kg (U.S. Gulf Coast), with regional sensitivity at \$1.00/kg and \$2.50/kg.
Parity-map generation	Evaluate Net LCOH over a grid in (p_e, ϕ) space; feasible points satisfy Net LCOH $\leq$ benchmark.
Sensitivity protocol	One-at-a-time perturbation around baseline; report Δ(Net LCOH) for each parameter change.
Figure interpretation	Numerical parity metrics and tabled results are reported alongside figures so conclusions do not rely on color alone.

- Delivered electricity price: ±\$10/MWh
- Credit magnitude: ±\$0.50/kg
- Electrolyzer efficiency: ±10%
- Capital cost: ±20%
- Capacity factor: ±10 percentage points
- Non-electric OPEX: ±20%

Sensitivities quantify Δ(Net LCOH) from each perturbation to identify the highest-leverage cost reduction pathways.

3.4. Parity Analysis and Feasibility Region Quantification

Economic parity is defined as:

$$\text{Net LCOH}(p_e, \phi) \leq P_{\text{benchmark}}, \tag{9}$$

with central benchmark $P_{\text{benchmark}}$ = \$1.70/kg for U.S. Gulf Coast SMR. Regional benchmark sensitivity uses \$1.00/kg and \$2.50/kg.

The feasibility region $\mathcal{F}$ comprises all (electricity price p_e, capacity factor ϕ) combinations achieving parity:

$$\mathcal{F} = \left\{ (p_e, \phi) : \frac{A}{\phi} + \frac{p_e}{1000} E_{\text{req}} + C_{\text{OPEX}} - C_{\text{credit}} \leq P_{\text{benchmark}} \right\}. \tag{10}$$

We report two viability metrics.

(1) Geometric viable fraction:

$$\Gamma_{\text{geom}} = \frac{\text{Area}\{(p_e, \phi) \in \mathcal{F}\}}{\text{Area}\{(p_e, \phi) \in \Omega\}}, \tag{11}$$

where Ω is the strategy-specific achievable operating domain. Γ_{geom} is a design-space metric and does not encode market likelihood.

(2) Market-weighted viable fraction:

$$\Gamma_w = \int_\Omega \mathbf{1}[\text{Net LCOH}(p_e, \phi) \leq P_{\text{benchmark}}]\, f(p_e, \phi)\, dp_e\, d\phi, \tag{12}$$

where $f(p_e, \phi)$ is the empirical joint density of delivered electricity price and achievable utilization for a given region and compliance regime.

Γ_{geom} answers "how much of the modeled operating space is viable," while Γ_w answers "how likely viability is under real operating conditions." We report both metrics to avoid over-interpreting geometric area as deployable probability.

Because region-specific empirical joint distributions are not available in this study, Γ_w is retained as a forward-implementation metric and is not used as a primary reported result. A short synthetic implementation example is provided in Supplementary Material S1 to illustrate workflow mechanics. A practical corridor-level Γ_w implementation would require at least: hourly delivered-price distributions (contract plus balancing outcomes), hourly achievable-utilization traces from resource-plus-storage portfolios, temporal EAC availability/matching data, and facility-operability constraints (minimum load, outage patterns). For example, an ERCOT-oriented implementation could combine ERCOT DAM/RTM price series, NREL wind/solar profile datasets, and hourly certificate-availability records from granular-EAC tracking systems to construct $f(p_e, \phi)$ for Gulf Coast screening.

Parity boundaries are also summarized through the minimum viable utilization at fixed electricity price:

$$\phi_{\min}(p_e) = \frac{A}{P_{\text{benchmark}} + C_{\text{credit}} - C_{\text{OPEX}} - \frac{p_e}{1000} E_{\text{req}}}. \tag{13}$$

Equation 13 follows directly by rearranging the parity inequality in Equation 4 for ϕat fixed $(p_e, C_{\text{credit}}, C_{\text{OPEX}}, E_{\text{req}})$.

Points where $\phi_{\min}$ exceeds achievable utilization define electricity-price ceilings and identify viability cliffs.

4. Results

4.1. Feasibility Region Contraction Under 45V Compliance

Figure 1 shows the modeled parity region under the central \$1.70/kg benchmark for two policy windows: transition-period Annual matching (2025–2029) and long-run Hourly matching (2030 onward). The key numerical result is that viability contracts materially under hourly compliance. Regional benchmark sensitivities (\$1.00/kg and \$2.50/kg) are reported in Table 5.

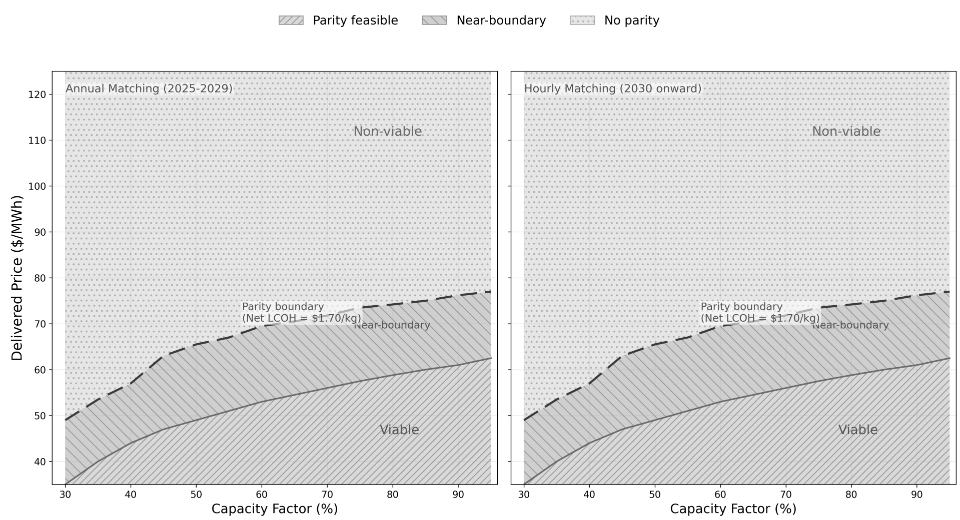

Figure 1: Annual- and hourly-matching parity regions at the central benchmark (Net LCOH = \$1.70/kg, Tier 1 credit). Grayscale hatching distinguishes viable, near-boundary, and non-viable zones; the near-boundary band denotes points within about \$0.20/kg of parity.

To preserve print readability (including grayscale reproduction), all key figure conclusions are also stated numerically in Equations and Tables.

4.1.1. Quantifying Viable Operating Space

We report the geometric viable fraction:

$$\Gamma_{\text{geom,strategy}} = \frac{\text{Area}\{(p_e, \phi) : \text{Net LCOH}(p_e, \phi) < P_{\text{benchmark}}\}}{\text{Area}\{\text{All achievable } (p_e, \phi)\}} \tag{14}$$

For electricity prices spanning \$20–80/MWh:

Annual matching (transition window, $\phi \in [0.70, 0.95]$):

- Viable fraction: $\Gamma_{\text{geom,annual}} = 0.775$
- At \$67/MWh, only $\phi \geq 0.87$ remains viable

Hourly matching (long-run window, $\phi \in [0.35, 0.65]$):

- Viable fraction: $\Gamma_{\text{geom,hourly}} = 0.672$
- At \$67/MWh, no combinations remain viable

These are geometric design-space metrics over assumed operating domains, not probability-of-success metrics. In practical terms, Γ approximates the share of modeled operating space where parity remains feasible under the stated constraints. Because Annual and Hourly policy windows impose different admissible ϕ domains, Γ_{geom} is interpreted as a within-domain screening metric; cross-window intuition is anchored with fixed-price thresholds (for example, at \$67/MWh Annual requires $\phi \geq 0.87$, while Hourly has no viable points).

4.1.2. Fragility Quantification

$$\frac{\Gamma_{\text{geom,hourly}}}{\Gamma_{\text{geom,annual}}} = \frac{0.672}{0.775} = 0.867 \tag{15}$$

This corresponds to a 13.3% relative reduction (10.3 percentage-point absolute reduction) in geometric viable space under hourly matching.

4.1.3. Interpretation: Dual Penalties of Hourly Matching

The viability contraction reflects compounding constraints:

1. **Lower utilization ceiling:** Hourly matching caps CF at 0.65 vs. 0.95 for Annual. The hyperbolic A/ϕ term penalizes lower utilization. Using the reported capital terms (\$0.62 vs. \$0.43/kg), the implied difference is \$0.19/kg.

2. **Shifted operating regime:** Hourly operation occurs in a steeper region of the A/ϕ curve, so CF misses have larger downside impact.
3. **Electricity-exposure coupling:** Lower-CF operation typically requires tighter power procurement and firming strategies, increasing sensitivity to delivered electricity prices.

4.1.4. Implications for Project Finance

The geometric contraction is directionally important for screening, but it should not be interpreted as default probability. Bankability should be evaluated with the market-weighted viability metric Γ_w defined in Section 3.4, using region-specific distributions for (p_e, ϕ). Γ_w is retained as a future implementation reference; its exclusion here reflects regional data unavailability, not methodological omission.

In practice, this implies:

- **Siting discipline:** Long-run hourly projects require stronger resource quality and procurement structure than transition-window annual cases.
- **Risk quantification:** Debt sizing should rely on Γ_w (or equivalent stochastic dispatch analysis), not Γ_{geom} alone.
- **Technology focus:** In hourly regimes, improvements that increase effective utilization and reduce delivered electricity volatility are disproportionately valuable.

4.2. Cost Structure and Capital Intensity Analysis

Table 3: Transition-window scenario economics (Annual matching, 2025–2029)

Scenario	**Match**	ϕ	p_e \$/MWh	**LCOH** \$/kg	**Net** \$/kg	**Gap** \$/kg	κ	Ψ_{credit}
1. High CF, low elec.	Annual	0.90	30	2.55	−0.45	−2.15	0.20	1.18
2. High CF, mid elec.	Annual	0.90	50	3.65	0.65	−1.05	0.12	0.82

Notes: Net LCOH uses the credit assumption attached to each scenario definition. Gap = Net LCOH − \$1.70/kg benchmark; negative gap indicates parity. Net LCOH < 0 indicates a subsidy-dominant edge case where modeled credit exceeds gross production cost.

Tables 3 and 4 report the modeled scenario economics by policy window. At the long-run hourly baseline ($\phi = 0.50$, \$67/MWh), gross LCOH is \$5.04/kg

Table 4: Long-run scenario economics (Hourly matching, 2030 onward)

Scenario	**Match**	ϕ	p_e \$/MWh	**LCOH** \$/kg	**Net** \$/kg	**Gap** \$/kg	κ	Ψ_{credit}
3. Mid CF, low elec.	Hourly	0.45	30	2.99	−0.01	−1.71	0.37	1.00
4. Mid CF, mid elec.	Hourly	0.50	67	5.04	2.04	+0.34	0.22	0.59
4b. **Mid CF, mid elec. + degradation stress**	**Hourly**	**0.50**	**67**	**5.34**	**2.34**	**+0.64**	**0.22**	**0.56**
5. Low CF, low elec.	Hourly	0.35	30	3.35	0.35	−1.35	0.46	0.90
6. Low CF, mid elec.	Hourly	0.35	50	4.45	1.45	−0.25	0.27	0.67
7. Hourly + storage	Hourly	0.65	55	3.67	0.67	−1.03	0.16	0.82

Notes: Net LCOH uses the credit assumption attached to each scenario definition. Gap = Net LCOH − \$1.70/kg benchmark; negative gap indicates parity. Net LCOH < 0 indicates a subsidy-dominant edge case where modeled credit exceeds gross production cost. Row 4b (bolded) reports the degradation-adjusted baseline stress described in Section 4.3.1. Row 4 is the non-degraded baseline reference.

and Net LCOH is \$2.04/kg, with electricity contributing about 73% of gross cost. The degradation-adjusted parallel baseline (Row 4b) yields gross LCOH \$5.34/kg and Net LCOH \$2.34/kg under the same operating point. Relative to the \$1.70/kg benchmark, the baseline-to-degradation parity-gap range is therefore +\$0.34/kg to +\$0.64/kg. Net LCOH values use scenario-specific credit assumptions rather than a single uniform credit across all rows.

4.2.1. Credit-Tier and Regional Benchmark Sensitivity Matrix

To explicitly visualize both partial-credit outcomes and regional benchmark context, Table 5 reports the baseline operating point across credit tiers (Panel A) and representative regional benchmark levels (Panel B).

Table 5 shows that partial-credit outcomes (Tier 2 and Tier 3) remain materially above parity across all benchmark cases considered, including \$2.50/kg. Because these partial-credit cases are uniformly non-viable in the modeled set, the main figures focus on Tier 1 boundaries; partial-credit implications are summarized qualitatively and in Table 5. As shown in Table 5, even Tier 2 credit does not close the parity gap under the \$2.50/kg benchmark (+1.54/kg).

Panel B of Table 5 shows the baseline Tier 1 case remains above parity in MENA and U.S. Gulf Coast benchmark ranges, while parity is achieved only under higher European benchmark levels.

Table 5: Credit-tier and regional benchmark sensitivity (baseline gross LCOH = \$5.04/kg)

Panel A. Credit-tier sensitivity matrix

Credit case	**Credit** \$/kg	Ψ_{credit} N/A	**Net LCOH** \$/kg	**Gap vs \$1.00** \$/kg	**Gap vs \$1.70** \$/kg	**Gap vs \$2.50** \$/kg
Tier 1	3.00	0.59	2.04	+1.04	+0.34	−0.46
Tier 2	1.00	0.20	4.04	+3.04	+2.34	+1.54
Tier 3	0.60	0.12	4.44	+3.44	+2.74	+1.94
No credit	0.00	0.00	5.04	+4.04	+3.34	+2.54

Panel B. Regional benchmark context at baseline Tier 1 (Net LCOH = \$2.04/kg)

Region/benchmark context	**Benchmark** \$/kg	**Gap vs benchmark** \$/kg	**Parity status**
MENA gas-rich range (low)	1.00	+1.04	No parity
MENA gas-rich range (high)	1.20	+0.84	No parity
U.S. Gulf Coast reference	1.70	+0.34	No parity
European import-sensitive range (low)	2.50	−0.46	Parity achieved
European import-sensitive range (high)	2.80	−0.76	Parity achieved

Panel A note: $\Psi_{\text{credit}} = C_{\text{credit}}/\text{LCOH}_{\text{gross}}$ using baseline gross LCOH = \$5.04/kg. Positive gap indicates no parity. Panel B note: Gap = Net LCOH − benchmark for baseline Tier 1; negative gap indicates parity margin.

4.2.2. Electricity-Dominated Cost Regime

The baseline capital intensity ratio $\kappa = 0.22$ indicates **electricity-dominated** economics, where electricity costs contribute about 4.6× more to LCOH than annualized capital recovery. This stands in contrast to historical hydrogen production analyses which often assume capital-intensive regimes ($\kappa > 0.60$) based on lower electricity prices (\$30–40/MWh) and higher capacity factors (0.90–0.97) achievable with grid-powered operation. As shown in Figure 2, small reductions in ϕ near 0.50 produce sharp LCOH increases through the hyperbolic capital-recovery term.

The shift to electricity domination reflects two 45V-specific constraints:

1. **Effective delivered electricity premium:** The \$67/MWh baseline can be decomposed as \$55/MWh contracted renewable energy, +\$4.4/MWh transmission and distribution losses (about 8%), +\$5.0/MWh firming/backup costs for minimum-load continuity, and +\$2.6/MWh ancillary/balancing services for hourly matching compliance. This represents a 22% premium over nominal PPA pricing, and a 103% premium over industrial grid rates (\$33/MWh) used in pre-IRA

hydrogen cost assessments.

2. **Constrained utilization:** Hourly temporal matching limits achievable capacity factor to 0.35–0.65 for renewable-coupled systems without grid backup (which would violate emissions requirements). Even with hybrid wind-solar generation and 2–4 hours of battery storage, $\phi = 0.50$ represents a realistic mid-range utilization, far below the 0.90–0.97 grid-enabled operation assumed in capital-intensive frameworks.

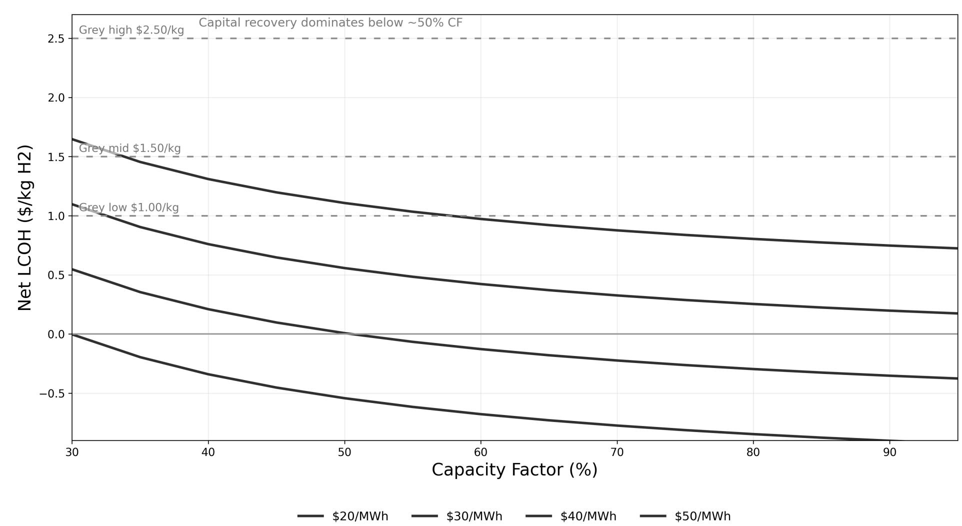

Figure 2: Net LCOH as a function of electrolyzer capacity factor across delivered-electricity cases ($20–50/MWh curves). Under hourly matching, the $\phi < 0.50$ region generally corresponds to non-viable operation for parity at the central benchmark.

4.2.3. Capital Intensity Variation Across Scenarios

Tables 3 and 4 reveal systematic κ variation with operating conditions:

- **High CF, low electricity** (Annual matching, excellent renewables): $\kappa = 0.20$. Capital contributes only 17% of LCOH despite high utilization because exceptionally low electricity costs ($30/MWh) dominate even optimized capital recovery.

- **High CF, mid electricity** (Annual matching, typical renewables): $\kappa = 0.12$. Grid balancing enables ϕ=0.90, minimizing capital burden to just 11% of LCOH. Electricity at \$50/MWh still dominates at 80%.
- **Mid CF, low electricity** (Hourly matching, excellent renewables): $\kappa = 0.37$. Lower utilization (ϕ=0.45) increases capital contribution to 27% despite cheap electricity. First scenario approaching balanced sensitivity.
- **Mid CF, mid electricity** (**BASELINE**, Hourly matching): $\kappa = 0.22$. Electricity-dominated but with meaningful capital sensitivity. Represents realistic 45V-compliant operation.
- **Low CF, low electricity** (Hourly matching, poor renewables or high curtailment): $\kappa = 0.46$. Low utilization (ϕ=0.35) elevates capital to 32% of LCOH. Approaching capital-intensive threshold ($\kappa = 0.50$).
- **Low CF, mid electricity** (Hourly matching, poor renewables): $\kappa = 0.27$. Despite low CF, mid-range electricity price keeps system electricity-dominated.
- **Hourly + backup storage** (Renewables + 8–12 hour storage): $\kappa = 0.16$. Storage enables ϕ=0.65, reducing capital intensity to 14% despite added storage capital cost. Electricity remains the largest component at 78%.

No realistic 45V-compliant scenario achieves capital-intensive regime ($\kappa > 0.60$). Even the worst-case low-CF scenario reaches only $\kappa = 0.46$, remaining electricity-dominated.

4.2.4. Credit-Dependency Ratio Analysis

Complementing capital intensity, we define the **credit-dependency ratio**:

$$\Psi_{\text{credit}} = \frac{C_{\text{credit}}}{\text{LCOH}_{\text{gross}}} \tag{16}$$

At baseline, $\Psi_{\text{credit}} = 3.00/5.04 = 0.59$, meaning 59% of gross production cost is offset by credit support. This high dependency creates **policy-induced fragility** distinct from capital structure:

- **Binary tier cliffs:** Emissions exceedances dropping from Tier 1 (\$3.00/kg) to Tier 2 (\$1.00/kg) impose \$2.00/kg cost jumps, 40% of baseline gross LCOH, from marginal compliance failures.

- **Temporal and policy-window risk:** Under the original IRA schedule, the 10-year credit window created post-subsidy cliffs (for example, projects commissioned in 2032 would face \$3.00/kg cost increases when credits expired in 2042). Subsequent federal legislation shortened the construction-start eligibility window for 45V to before January 1, 2028, which shifts this cliff earlier for new projects and increases development-timing risk at the same Ψ_{credit} level [31, 32].

- **Compounding with utilization:** High Ψ_{credit} amplifies capacity factor fragility because credit per kg is fixed while capital cost per kg scales hyperbolically. A project at $\Psi_{\text{credit}} = 0.59$ and $\phi = 0.50$ experiences 1.8× greater absolute cost escalation from 10-point CF reduction than an unsubsidized project ($\Psi_{\text{credit}} = 0$) with identical κ.

The κ-Ψ_{credit} dual metrics indicate green hydrogen occupies a unique economic regime: **electricity-dominated** ($\kappa = 0.22$) yet **credit-dependent** ($\Psi_{\text{credit}} = 0.59$). Traditional capital-intensive frameworks ($\kappa > 0.60$) prioritize capital cost reduction; electricity-dominated-but-unsubsidized frameworks ($\kappa < 0.40$, $\Psi_{\text{credit}} < 0.20$) prioritize electricity cost. Green hydrogen requires addressing *both* electricity procurement and credit compliance fragility simultaneously.

4.2.5. Threshold Example: Credit Tier Sensitivity

Consider a marginal project designed for Tier 1 credit eligibility (ϕ=0.59, \$63/MWh electricity, achievable with optimized hybrid wind-solar generation and 2–4 hours battery storage). A 10-percentage-point capacity factor reduction (ϕ=0.59 $\rightarrow$ 0.49) is treated as an assumed stress condition that coincides with an emissions-threshold exceedance and Tier 1-to-Tier 2 downgrade. Mechanistically, this linkage can occur through three channels under hourly compliance: higher reliance on residual marginal-grid imports during renewable shortfalls, more part-load/start-stop operation that raises effective kWh/kg, and reduced clean-matching ratio of qualified electricity to electrolyzer load. The tier transition is therefore scenario-imposed in this screening model rather than endogenously dispatched.

At high CF (ϕ=0.59):

$$\begin{aligned}\mathrm{LCOH}_{\mathrm{gross}} &= \frac{0.4048}{0.59} + 0.063 \times 55 + 0.548 \\ &= 0.686 + 3.465 + 0.548 = 4.70\,\$/\mathrm{kg} \\ \text{Net LCOH}_{\text{Tier 1}} &= 4.70 - 3.00 = 1.70\,\$/\mathrm{kg}\end{aligned}$$

This is exact parity with the \$1.70/kg benchmark.

At reduced CF (ϕ=0.49):

$$\begin{aligned}\mathrm{LCOH}_{\mathrm{gross}} &= \frac{0.4048}{0.49} + 0.063 \times 55 + 0.548 \\ &= 0.826 + 3.465 + 0.548 = 4.84\,\$/\mathrm{kg} \\ \text{Net LCOH}_{\text{Tier 2}} &= 4.84 - 1.00 = 3.84\,\$/\mathrm{kg}\end{aligned}$$

This case receives Tier 2 credit only. As shown in Table 5, Tier 2 remains above parity even under the \$2.50/kg benchmark case.

Economic penalty: The 10-point CF reduction (17% decrease) combined with credit tier drop produces a \$2.14/kg net cost increase (126% escalation), comprising \$0.14/kg from reduced utilization plus \$2.00/kg from lost credit eligibility. This \$2.14/kg increment is measured relative to the Tier 1 parity case (\$3.84/kg − \$1.70/kg). This demonstrates the compounding fragility of high credit dependency ($\Psi_{\text{credit}} \approx 0.60$ at both CFs): small operational deviations trigger large policy-induced cost cliffs unrelated to technology or market fundamentals.

Projects designed for marginal parity under Tier 1 compliance operate with minimal buffer against either capacity factor shortfalls or electricity price increases. Figure 3 illustrates the narrow viable band around $\phi = 0.50$ and the cliff-vulnerable region below $\phi_{\min}$, where small utilization reductions trigger steep net-LCOH escalation and viability loss. The dual fragility metrics (κ and Ψ_{credit}) indicate that 45V-compliant green hydrogen faces two independent collapse modes: (1) electricity cost escalation overwhelming economics despite low capital intensity, and (2) emissions compliance failures eliminating credit eligibility despite meeting technological performance targets.

4.3. Joint-Parameter Stress Matrix (Electricity, Utilization, Credit Tier)

To complement one-at-a-time perturbations, Table 6 reports a three-parameter stress matrix across delivered electricity price (p_e), capacity factor

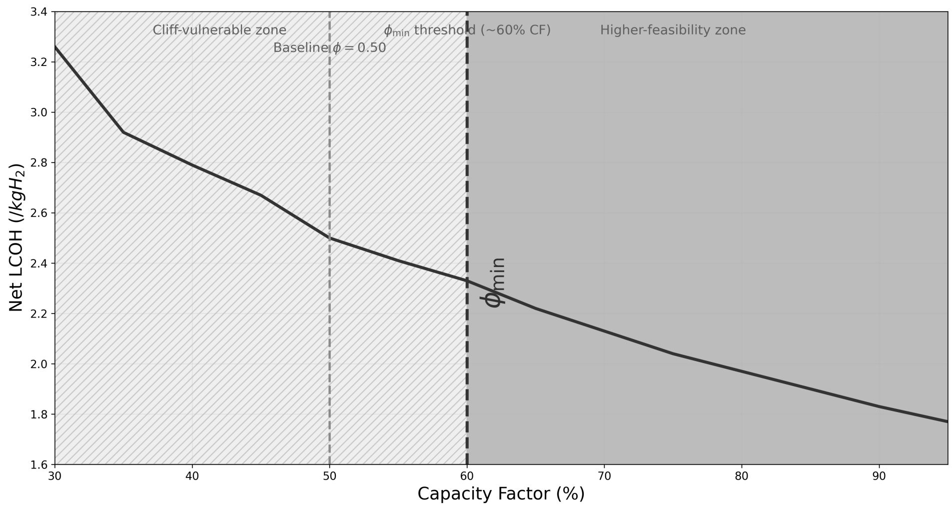

Figure 3: Utilization-threshold behavior around the hourly baseline. The left shaded zone marks cliff-vulnerable operation where Net LCOH exceeds \$1.70/kg despite Tier 1 credit.

(ϕ), and credit tier. This interaction view is still algebraic (not dispatch-simulated), but it provides systematic coverage of joint stress states beyond single-point examples.

Table 6 shows clear interaction structure: Tier 1 retains a narrow viable corridor at moderate electricity prices and higher utilization, while Tier 2 and Tier 3 are uniformly non-viable across this operating grid. This matrix-based view supports the threshold narrative in Section 4.2.5 using systematic joint perturbations rather than a single illustrative point.

4.3.1. Degradation-Adjusted Baseline Stress Case

Because stack degradation and replacement materially affect parity margin, we report a degradation-adjusted baseline stress case in the core results. Assuming 1%/year effective efficiency degradation within 10-year stack cycles and two replacements over a 30-year project life (years 10 and 20), the incremental levelized burden is:

$$\begin{aligned}\Delta\mathrm{LCOH}_{\mathrm{degradation}} &\approx +\$0.17/\mathrm{kg}\ (\text{higher electricity use}) + \$0.13/\mathrm{kg}\ (\text{replacement-capital recovery})\\ &= +\$0.30/\mathrm{kg}.\end{aligned}$$

Table 6: Joint stress matrix: Net LCOH (\$/kg) and parity status across p_e, ϕ, and credit tier (central benchmark = \$1.70/kg)

Panel A. Tier 1 credit (\$3.00/kg)

p_e (\$/MWh)	$\phi = 0.40$	$\phi = 0.50$	$\phi = 0.60$	$\phi = 0.70$
50	1.31 (P)	1.11 (P)	0.97 (P)	0.88 (P)
60	1.86 (NP)	1.66 (P)	1.52 (P)	1.43 (P)
67	2.25 (NP)	2.04 (NP)	1.91 (NP)	1.81 (NP)
75	2.69 (NP)	2.48 (NP)	2.35 (NP)	2.25 (NP)

Panel B. Tier 2 credit (\$1.00/kg)

p_e (\$/MWh)	$\phi = 0.40$	$\phi = 0.50$	$\phi = 0.60$	$\phi = 0.70$
50	3.31 (NP)	3.11 (NP)	2.97 (NP)	2.88 (NP)
60	3.86 (NP)	3.66 (NP)	3.52 (NP)	3.43 (NP)
67	4.25 (NP)	4.04 (NP)	3.91 (NP)	3.81 (NP)
75	4.69 (NP)	4.48 (NP)	4.35 (NP)	4.25 (NP)

Panel C. Tier 3 credit (\$0.60/kg)

p_e (\$/MWh)	$\phi = 0.40$	$\phi = 0.50$	$\phi = 0.60$	$\phi = 0.70$
50	3.71 (NP)	3.51 (NP)	3.37 (NP)	3.28 (NP)
60	4.26 (NP)	4.06 (NP)	3.92 (NP)	3.83 (NP)
67	4.65 (NP)	4.44 (NP)	4.31 (NP)	4.21 (NP)
75	5.09 (NP)	4.88 (NP)	4.75 (NP)	4.65 (NP)

P = parity achieved (Net LCOH $\leq$ \$1.70/kg); NP = no parity. Values computed from Equations 1 and 4 with baseline $A = 0.4048$ and $C_{\mathrm{OPEX}} = \$0.548$/kg.

Applying this to the hourly baseline moves Net LCOH from \$2.04/kg to about \$2.34/kg, widening the parity gap versus the \$1.70/kg benchmark from +\$0.34/kg to +\$0.64/kg. This degradation-adjusted case is reported directly in Table 4 (Row 4b) and is kept separate from tornado bars because it combines lifecycle degradation and replacement-schedule assumptions rather than a single one-at-a-time perturbation.

4.3.2. Downstream Cost Translation of Hydrogen Parity Gaps

To connect hydrogen parity gaps to end-use markets, Table 7 translates the baseline (+\$0.34/kg) and degradation-adjusted (+\$0.64/kg) Net-LCOH gaps into downstream cost increments using:

$$\Delta C_{\text{downstream}} = I_{\text{H}_2} \times \Delta C_{\text{H}_2}, \tag{17}$$

where I_{H_2} is hydrogen intensity of the downstream product.

Table 7: Illustrative downstream translation of hydrogen parity gaps

Downstream product	**Hydrogen intensity**	**Cost transfer at +\$0.34/kg H_2**	**C**
Ammonia (NH_3, stoichiometric minimum)	176 kg H_2/t NH_3	+\$60/t NH_3	
H_2-DRI steel (illustrative midpoint)	55 kg H_2/t steel	+\$19/t steel	

Notes: Ammonia intensity is stoichiometric (17.65 wt% H_2 in NH_3). Steel intensity is an illustrative midpoint for hydrogen-DRI pathways and is used for screening translation rather than a full process model. Values are incremental and should be added to pathway-specific baseline production costs.

Table 7 indicates that seemingly modest hydrogen parity gaps propagate into material downstream cost shifts. This is particularly relevant for sectors where hydrogen is an intermediate input rather than a final product.

4.4. Parameter Sensitivity and Investment Hierarchy

As visualized in Figure 4, delivered electricity price dominates investment sensitivity, with credit magnitude a close second under the baseline $\Psi_{\text{credit}} = 0.59$. The ranking then follows with electrolyzer efficiency, capacity factor, electrolyzer capital cost, and non-electric OPEX.

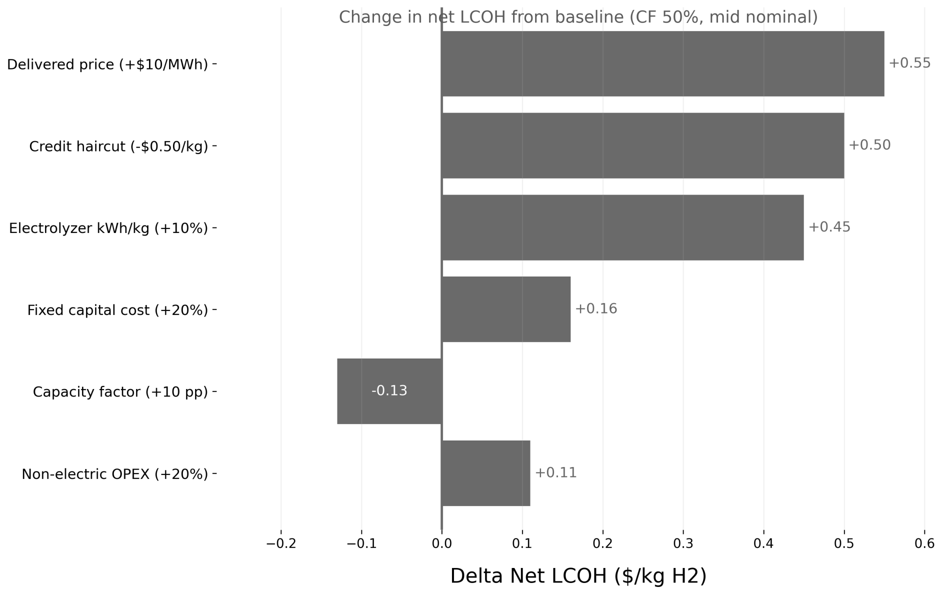

Figure 4: Tornado sensitivity of Net LCOH around the baseline case ($\phi = 0.50$, $p_e = \$67$/MWh, $C_{\text{cap}} = \$800$/kW). Bars align with Table 8; the capacity-factor bar reports the upside case (+10 percentage points), while Table 8 reports the full asymmetric range (+0.20 / −0.13).

Table 8: Parameter sensitivity rankings: absolute Δ(Net LCOH) from realistic perturbations

Rank	**Parameter**	**Perturbation**	**ΔLCOH ($/kg)**
1	Delivered electricity price	±$10/MWh	±0.55
2	45V credit magnitude	±$0.50/kg	±0.50
3	Electrolyzer efficiency	±10%	±0.45
4	Capacity factor	±10 pp	+0.20 / −0.13
5	Electrolyzer capital cost	±20%	±0.16
6	Non-electric OPEX	±20%	±0.11

Baseline: $\phi = 0.50$, $p_e = \$67$/MWh, $C_{\text{cap}} = \$800$/kW, $E_{\text{req}} = 55$ kWh/kg. Capacity factor shows asymmetric impact due to hyperbolic A/ϕ term.

4.4.1. Sensitivity Rankings and Magnitudes

Figure 4 and Table 8 present absolute LCOH impacts from realistic parameter perturbations. The sensitivity hierarchy orders by economic leverage:

1. Delivered electricity price (±$10/MWh): ±$0.55/kg

- Linear pass-through: $\Delta\text{LCOH} = (\Delta p_e/1000) \times E_{\text{req}} = (10/1000) \times 55 = \$0.55/\text{kg}$
- Exceeds all other sensitivities due to 73% electricity contribution to baseline LCOH
- Asymmetry: None (linear in both directions)

2. Credit magnitude (±$0.50/kg): ±$0.50/kg

- One-for-one pass-through to net cost
- High ranking despite modest perturbation reflects $\Psi_{\text{credit}} = 0.59$ (credit equals 59% of gross cost)
- Example: Tier 1 ($3.00) → Tier 2 ($1.00) drop imposes $2.00/kg penalty, 40% of gross baseline LCOH
- Asymmetry: None (credit is additive term)

3. Electrolyzer efficiency (±10%): ±$0.45/kg

- Compound effect through both capital and electricity:
  - Capital component: A scales with E_{req}, contributing ±$0.08/kg
  - Electricity component: Direct consumption change, contributing ±$0.37/kg
  - Total: $0.45/kg (linear combination)
- 10% efficiency improvement (55 → 49.5 kWh/kg) provides comparable benefit to $8/MWh electricity reduction
- Asymmetry: None (both components linear in E_{req})

4. Capacity factor (±10 percentage points): +$0.20/kg (downside), -$0.13/kg (upside)

- **1.5× asymmetry:** Downside penalty exceeds upside benefit
- Source: Hyperbolic A/ϕ term. At ϕ=0.50, $|\partial\text{LCOH}/\partial\phi| = A/\phi^2 = 0.4048/0.25 = 1.62$ \$/kg per 0.10 change
- Downside (ϕ=0.50 → 0.40): LCOH increases from \$5.04 to \$5.24/kg (+\$0.20)
- Upside (ϕ=0.50 → 0.60): LCOH decreases from \$5.04 to \$4.91/kg (-\$0.13)
- Asymmetry validates hyperbolic cost escalation at low utilization, explaining Hourly matching fragility

5. Electrolyzer capital cost (±20%): ±\$0.16/kg

- Despite large 20% perturbation (\$800 → \$640 or \$960/kW), impact is only \$0.16/kg
- Reflects low capital intensity ($\kappa = 0.22$): capital contributes just 16% of baseline LCOH
- Calculation: $\Delta A = \Delta C_{\text{cap}} \times \text{CRF} \times E_{\text{req}}/8760 = \pm 160 \times 0.0806 \times 55 / 8760 = \pm\$0.081/\text{kg}$; at ϕ=0.50, $\Delta\text{LCOH} = \pm 0.081/0.50 = \pm\$0.16/\text{kg}$
- Asymmetry: None (linear in C_{cap})

6. Non-electric OPEX (±20%): ±\$0.11/kg

- Direct pass-through: $\Delta C_{\text{OPEX}} = \pm 0.548 \times 0.20 = \pm\$0.11/\text{kg}$
- Lowest sensitivity reflects small 11% contribution to baseline LCOH
- Components: water (\$0.02/kg), maintenance (\$0.388/kg), labor (\$0.10/kg), insurance/taxes (\$0.04/kg). The maintenance term includes stack-replacement accrual and fixed O&M conventions aligned to DOE H2A v3.2024 accounting assumptions [3].
- Asymmetry: None (linear in C_{OPEX})

Water cost remains a small share at the baseline assumption, but site-specific stress can be non-trivial. For example, increasing water-related cost from \$0.02/kg to \$0.20/kg H_2 (desalination/transport-constrained case) adds +\$0.18/kg to Net LCOH; at \$0.50/kg H_2, the increment is +\$0.48/kg. This does not overturn the electricity-dominance result, but it can materially tighten siting margins in water-stressed regions.

4.4.2. Investment Hierarchy and Strategic Implications

The tornado ranking shows that electricity procurement provides about 3.4× greater economic leverage than capital cost reduction: a \$10/MWh delivered electricity improvement (\$0.55/kg benefit) exceeds the impact of 20% electrolyzer capital cost reduction (\$0.16/kg benefit) despite the latter representing a \$160/kW capital investment.

This inverts traditional hydrogen technology roadmaps which prioritize electrolyzer cost-down (target: \$1000/kW → \$500/kW by 2030) as the primary parity pathway. The inversion stems from electricity-dominated cost structure: at \$67/MWh effective pricing and 55 kWh/kg consumption, electricity contributes \$3.69/kg (73%) of gross LCOH while capital recovery contributes only \$0.81/kg (16%). A 20% capital cost reduction therefore reduces total LCOH by only 3.2%, whereas a comparable 15% electricity price reduction (\$67 → \$57/MWh) reduces LCOH by 10.9%, i.e., materially larger impact.

Policy and R&D implications:

1. **Public R&D prioritization:** Continued investment in electrolyzer stack materials, catalyst loading reduction, and membrane durability yields diminishing returns in electricity-dominated regimes ($\kappa < 0.30$). Greater impact comes from renewable integration research addressing firming strategies, hybrid wind-solar optimization, transmission loss minimization, and storage cost reduction, all reducing effective delivered electricity price.
2. **Policy mechanism alignment:** Production tax credits (\$3/kg for 10 years, value scaling with production) are better aligned with electricity-dominated economics than investment tax credits (30% of capital cost, insensitive to utilization and electricity costs). A policy shift toward electricity cost subsidies (renewable energy zones, transmission infrastructure grants, PPA price guarantees) would provide 2–3× greater economic impact per dollar of public investment than capital grants.
3. **Site selection dominance:** Project developers create more value through renewable resource site optimization (\$10–20/MWh electricity price variation from resource quality, yielding \$0.55–1.10/kg LCOH impact) than through equipment vendor selection (\$100–200/kW capital cost variation from technology choice, yielding \$0.10–0.20/kg impact). This explains observed industry behavior: major hydrogen project announcements cluster in exceptional renewable corridors (Patagonia

wind: \$25/MWh; Western Australia solar: \$30/MWh; Morocco hybrid: \$35/MWh) despite higher infrastructure costs, rather than low-capital-cost manufacturing regions.

4. **Technology development sequencing:** For projects already committed to specific sites and electricity contracts, residual optimization focuses on: (1) efficiency improvement (10% efficiency = \$0.45/kg, comparable to \$8/MWh electricity reduction), (2) capacity factor maximization within hourly matching constraints (\$0.13–0.20/kg from 10-point CF increase), (3) capital cost reduction (\$0.16/kg from 20% capital cost decrease). Efficiency improvements provide 2.8× greater leverage than capital cost reduction.

The electricity-over-capital priority persists even under optimistic 2030 technology projections (\$500/kW capital cost, 50 kWh/kg efficiency). At \$60/MWh electricity (achievable with excellent hybrid renewables plus modest storage):

$$
\begin{aligned}
A_{2030} &= \frac{500 \times 0.0806 \times 50}{8760} = 0.2298 \text{ \$/kg per unit } \phi \\
\mathrm{LCOH}_{2030} &= \frac{0.2298}{0.60} + \frac{60}{1000} \times 50 + 0.40 = 0.383 + 3.000 + 0.40 = 3.78 \text{ \$/kg} \\
\kappa_{2030} &= \frac{0.2298}{3.000} = 0.077 \quad \text{(even more electricity-dominated)}
\end{aligned}
$$

With $\kappa_{2030} = 0.077$, electricity contributes 79% of LCOH while capital contributes only 10%. A \$10/MWh electricity reduction provides \$0.50/kg benefit, while 20% further capital cost reduction (\$500 → \$400/kW) provides only \$0.08/kg, a **6.3× differential**. Technology maturation thus *amplifies* rather than reverses the electricity-over-capital hierarchy, suggesting this inversion is structural to renewable hydrogen economics rather than a transient artifact of current high electrolyzer costs.

5. Discussion

5.1. Positioning Against Existing Literature

This study's baseline case ($\phi = 0.50$, \$67/MWh delivered electricity, \$800/kW electrolyzer capital cost, 55 kWh/kg efficiency) yields gross LCOH of \$5.04/kg and Net LCOH of \$2.04/kg (Table 4, Figure 4). This result is within the range of recent techno-economic studies but remains above the central parity benchmark of \$1.70/kg. Interaction effects across electricity price, utilization, and credit tier are reported explicitly in Table 6, which complements one-at-a-time sensitivity results. NREL H2A v3.2024 reports approximately \$4.50/kg for grid-powered PEM operation at very high capacity factor and lower industrial electricity pricing, while IEA 2023 reports \$5.00–6.00/kg for renewable-coupled operation at lower utilization [1, 3, 33]. Recent Applied Energy studies report comparable sensitivity to dispatch realism, curtailment, and delivered-electricity assumptions across steel, storage-coupled, and regional hub cases [7, 9, 19, 24]. The DOE \$2.00/kg figure is a forward policy target, not the gray-hydrogen parity benchmark used in this analysis (central \$1.70/kg with \$1.00/\$2.50 sensitivity bounds). Downstream propagation is quantified in Table 7, which translates hydrogen parity gaps into illustrative ammonia and H_2-DRI steel cost increments.

Our modestly higher LCOH (\$5.04/kg vs. \$4.50 NREL baseline) primarily reflects 45V-specific compliance constraints not captured in pre-IRA assessments [5, 6]:

1. **Effective delivered electricity price (\$67/MWh)** is represented as \$55/MWh contracted renewable energy plus about \$4.4/MWh losses, \$5.0/MWh firming/backup, and \$2.6/MWh ancillary/balancing services required for hourly temporal matching compliance. This 103% premium over NREL's \$33/MWh industrial grid rate represents real-world complications of procuring carbon-eligible electricity under Section 45V requirements rather than unencumbered industrial power contracts [5, 6].
2. **Capacity factor (0.50)** reflects achievable utilization with hybrid wind-solar generation plus 2–4 hours of battery storage, balancing hourly matching constraints against capital underutilization penalties. This is lower than NREL's grid-enabled 0.97 (which assumes dispatchable electrolyzer operation decoupled from renewable generation constraints) but achievable without violating 45V temporal matching from 2030 onward. Our CF aligns with IEA renewable-coupled estimates (0.40–0.50) for projects without grid backup and with recent meteorological and hybrid-supply Applied Energy cases [1, 5–8].
3. **Electrolyzer system efficiency (55 kWh/kg, 62% HHV)** adopts field-demonstrated performance including auxiliary loads (compression, cooling, controls) rather than stack-level manufacturer targets. NREL

H2A baseline (52 kWh/kg, 66% HHV) represents best-achievable performance under ideal conditions; our 6% degradation allowance matches industry operator reports of sustained multi-year performance [3].

The 12% LCOH premium over NREL H2A (\$5.04 vs. \$4.50) decomposes as: +\$0.37/kg from higher electricity costs (103% price premium × 73% electricity contribution), +\$0.11/kg from efficiency degradation (3 kWh/kg × \$0.067/kWh), and +\$0.06/kg from capacity factor underutilization (hyperbolic capital recovery at 0.50 vs. 0.97). This demonstrates that 45V compliance burden manifests primarily through electricity procurement complications, not electrolyzer technology limitations. The \$67/MWh delivered-electricity baseline is therefore a central assumption: if transmission bottlenecks persist or renewable buildout slows, effective delivered cost can remain above this level; if congestion and balancing costs decline with grid expansion, the delivered-cost trajectory can improve materially. RFF, RMI, and CATF sources are used here as policy-interpretation context rather than primary quantitative authorities; core quantitative results are produced by the TEA equations and scenario calculations reported in Sections 3–4 and benchmarked against peer-reviewed and DOE/IEA sources.

5.2. Methodological Positioning and Scope

To keep the manuscript within Applied Energy main-text length targets, the extended methodological-positioning discussion is provided in Supplementary Material S1 (submitted as a separate PDF with this manuscript). The core contributions retained in the main narrative are: (1) dual fragility metrics (κ and Ψ_{credit}), (2) viability-region contraction under hourly compliance, (3) investment hierarchy inversion favoring delivered-electricity optimization over electrolyzer capital-cost reduction, and (4) threshold nonlinearity that produces parity cliffs.

5.3. Implications for DOE Hydrogen Shot and 2030 Targets

The DOE Hydrogen Shot initiative targets \$1/kg clean hydrogen production cost by 2031, projecting this requires electrolyzer capital cost reduction to \$500/kW, efficiency improvement to 50 kWh/kg, and high utilization ($\phi > 0.80$) enabled by low-cost grid electricity or optimized hybrid renewables [33]. Recent benchmark updates continue to show wide regional dispersion in both policy support and delivered-cost trajectories [18, 34–36]. DOE materials generally frame this as a technology-cost target rather than a post-subsidy market price; however, because public interpretation is sometimes mixed, this paper reports both gross and net cost contexts explicitly. Our findings reveal that achieving \$1/kg *unsubsidized* cost remains infeasible even under these optimistic assumptions when 45V compliance constraints and realistic electricity procurement challenges are incorporated [5, 6, 26, 27].

Under 2030 technology projections (\$500/kW, 50 kWh/kg, 7% WACC, 30-year life), gross (pre-credit) LCOH at $\phi = 0.80$ and \$50/MWh effective electricity reaches \$3.10/kg, triple the \$1/kg target. Achieving \$1/kg unsubsidized requires either: (1) \$15/MWh effective delivered electricity (lower than any current renewable PPA pricing even before accounting for transmission, firming, and 45V matching costs); (2) 80% HHV electrolyzer efficiency (about 55 kWh/kg $\rightarrow$ 49 kWh/kg at system level, roughly an 11% improvement beyond the baseline assumption); or (3) \$200/kW installed capital cost (60% below bottom-up manufacturing cost estimates for current bill-of-materials).

Section 4 now reports a degradation-adjusted baseline stress case in the core results. Under a 1%/year effective efficiency degradation path with 10-year stack cycles and two replacements over 30 years, the incremental burden is about +\$0.30/kg (+\$0.17/kg electricity, +\$0.13/kg replacement-capital recovery at 7% WACC). This moves baseline Net LCOH from \$2.04/kg to about \$2.34/kg, widening the parity gap under the \$1.70/kg reference benchmark to about +\$0.64/kg.

This reveals the \$3/kg production tax credit is not only a *temporary deployment bridge* pending technology maturation; it can function as a structural economic requirement under constrained utilization conditions [4, 5]. Even with aggressive 2030 technology assumptions, $\Psi_{\text{credit}} > 0.50$ persists, indicating post-subsidy cliff risk. Under the original IRA horizon, projects commissioned in 2032 would face \$2–3/kg LCOH increases when credits expired in 2042; under the accelerated construction-start eligibility deadline (before January 1, 2028), that de-risking window is materially shorter, increasing execution and financing pressure for near-term projects [31, 32].

The policy implication is that sustained green hydrogen deployment at scale likely requires either: (1) permanent production subsidies scaled to carbon price differentials (converting temporary 45V to permanent carbon pricing mechanism); (2) breakthrough electricity cost reductions through grid-scale storage, advanced nuclear, or geothermal baseload penetration; or (3) acceptance of higher hydrogen costs in end-use markets with limited decarbonization alternatives (aviation, steelmaking, ammonia synthesis), internalizing climate externalities through regulatory mandates rather than economic parity.

Consistent with this screening heuristic, technologies operating near or above $\Psi_{\text{credit}} \approx 0.50$ generally face different commercialization pathways than moderately subsidized technologies ($\Psi_{\text{credit}} < 0.30$). The latter can more plausibly graduate from subsidy dependence as learning curves mature; the former typically require durable policy support or step-change reductions in orthogonal systems (electricity generation/transmission, not only process equipment).

5.4. Implications for Developers, Regulators, and Grid Planners

The results imply different actions for different decision-makers. For project developers, priority shifts from equipment-only optimization toward contract and operations design: hybrid procurement portfolios, explicit downside buffers on capacity factor, and credit-contingent offtake structures become first-order bankability tools. For developers, the results imply that electricity contracting strategy is the primary determinant of bankability under 45V, exceeding the leverage of further electrolyzer capital cost reductions. For lenders and investment committees, covenant design should incorporate credit-tier stress cases (Tier 1 to Tier 2) and utilization downside corridors rather than relying on single-point parity assumptions. Because this framework is screening-resolution, financing is represented through blended WACC rather than explicit project debt sculpting; as an illustrative check, raising blended WACC from 7% to 8% (a levered-structure stress proxy) increases baseline Net LCOH by about +\$0.08/kg at $\phi = 0.50$, while leaving the electricity-dominance ranking intact. A simple 60/40 debt-equity proxy (6% debt, 10% equity; blended WACC $\approx$ 7.6%) gives an intermediate shift of about +\$0.05/kg, again second-order relative to electricity-price and credit-tier sensitivities. Here, ”bankability” is used in a screening sense (parity resilience under operating and policy stress), not as a substitute for full lender underwriting with DSCR/LLCR cash-flow tests.

Water availability should also be treated as a siting constraint even when modeled water OPEX appears small (\$0.02/kg in the baseline). Several high-quality renewable corridors (e.g., Patagonia and parts of Western Australia) face seasonal or structural water stress, so practical site optimization should screen on joint electricity-resource quality, water security, and permitting complexity rather than electricity price alone. In constrained basins, desalination, reuse infrastructure, or transport requirements can shift optimal siting away from the purely lowest-cost renewable profile.

For regulators and grid planners, the main implication is coordination risk. To preserve deployment momentum, hourly matching must be paired with parallel investments in transmission buildout, congestion management, and clean-firming availability; otherwise compliance can tighten faster than system capability and convert a policy incentive into a deployment bottleneck. Final 45V rules provide limited near-term flexibility through a transition period with annual accounting before full hourly accounting applies to later tax years, which may ease early implementation friction but does not change the long-run fragility mechanisms identified here [26, 27]. This flexibility could modestly increase the effective long-run utilization ceiling relative to the strict $\phi \leq 0.65$ envelope used in the base hourly window, slightly expanding $\Gamma_{\text{geom,hourly}}$ while preserving the same qualitative driver hierarchy. A robust implementation pathway pairs emissions-integrity rules with grid-operability measures (deliverability expansion, temporal accounting clarity, and transparent credit-verification methods) so compliance stringency and operational feasibility evolve together [14–16]. Priority levers include regionally prequalified clean energy contracts, guaranteed transmission access for electrolyzers, and harmonized emissions accounting protocols to reduce siting risk.

5.5. Structural Analogies to Other Subsidy-Dependent Clean Energy Technologies

The dual fragility metrics (κ and Ψ_{credit}) and viable-fraction methodology (Γ) developed here are structurally analogous to other capital-intensive, subsidy-dependent clean energy technologies facing policy-compliance constraints:

- **Sustainable Aviation Fuels (SAF):** Section 45Z provides \$1.25–1.75 /gal production tax credit (2025–2027), representing $\Psi_{\text{credit}} \approx 0.45$–$0.60$ of Fischer-Tropsch or HEFA production costs. Hourly matching requirements for electricity-intensive SAF pathways (power-to-liquids) would face similar Γ contraction as hydrogen. The Ψ_{credit} framework quantifies post-credit cliff risk when 45Z expires (2028 without extension).

- **Carbon Capture and Storage:** 45Q credits (\$85/ton direct air capture, \$60/ton point-source) often equal or exceed facility operating costs ($\Psi_{\text{credit}} > 1.0$ for some configurations), creating extreme policy dependency. The κ-Ψ_{credit} framework distinguishes capital-intensive

CO_2 transport infrastructure (high κ, low Ψ_{credit}) from operating-cost-intensive capture processes (low κ, high Ψ_{credit}), requiring different risk hedging strategies.

- **Power-to-Liquids (PtL):** Combined investment tax credit (30% ITC) and production tax credit (renewable fuel credits, LCFS) can yield $\Psi_{\text{credit}} \approx 0.40$–$0.50$. Temporal matching requirements for renewable electricity sourcing create analogous Γ contraction, while high electricity intensity produces electricity-dominated cost structures ($\kappa < 0.30$) where procurement optimization exceeds equipment cost reduction in economic leverage.

Recent U.S. policy changes reinforce this cross-technology framing: the same legislation that shortened 45V eligibility for clean hydrogen also revised 45Q support structure for carbon-management pathways, shifting relative policy leverage across hydrogen value chains [31, 37]. This study suggests $\Psi_{\text{credit}} \approx 0.50$ as a screening heuristic (not a universal threshold) for subsidy-graduation feasibility: technologies with $\Psi_{\text{credit}} < 0.50$ may plausibly approach unsubsidized competitiveness through incremental improvement, while cases above this level typically require either major input-cost reduction or more durable policy support. As a simple illustrative non-hydrogen example, a PtL-SAF pathway with gross cost \$3.60/gal and credit \$1.50/gal gives $\Psi_{\text{credit}} = 0.42$; a credit haircut to \$1.00/gal lowers support to $\Psi_{\text{credit}} = 0.28$ but still leaves net cost materially policy-sensitive. This example is illustrative only and is not produced by a unified SAF dispatch model in this paper.

The same logic extends to ammonia and synthetic-fuels pathways that inherit hydrogen's electricity exposure: once compliance-qualified operating hours are constrained, levelized economics become highly sensitive to utilization floors and credit eligibility continuity. In that regime, cross-sector comparisons should be made on a common pair of metrics (capital intensity and credit dependency), not on standalone headline LCOH values.

This dichotomy has implications for climate policy design: attempting to commercialize high-Ψ_{credit} technologies through temporary deployment incentives may increase stranded-asset risk when subsidies expire, while framing them as long-lived public infrastructure (analogous to grid transmission justified by externality benefits) can enable more transparent cost-benefit analysis of long-term support requirements.

This analysis employs a simplified LCOH model intended for screening and comparative decision contexts rather than site-specific underwriting. Scope boundaries are explicit: no endogenous hourly dispatch optimization, no probabilistic Γ_w implementation from empirical corridor data, no explicit debt-service/DSCR financing model, and no full plant-level integration of water logistics, dynamic degradation, start-stop penalties, or buffer-storage dispatch between production and offtake. In addition, this study assumes the statutory 45V credit structure as enacted and does not model policy-change risk (for example, reinterpretation, implementation delay, or early sunset), which is material when baseline economics are highly credit-dependent ($\Psi_{\text{credit}} = 0.59$). It also does not endogenize second-order policy feedback from accelerated 45Y/48E phase-down timing, which could tighten delivered-electricity trajectories if renewable buildout slows in some regions [37]. These limitations do not affect the qualitative conclusion that 45V compliance materially narrows and destabilizes parity conditions, but they define where higher-fidelity dispatch-and-finance extensions are required. Future work should integrate hourly dispatch modeling with location-specific renewable profiles, empirical EAC/price distributions for Γ_w, and project-finance cash-flow constraints.

6. Conclusion

This study presented a decision-grade parity mapping framework for 45V-aligned clean hydrogen with explicit treatment of utilization and credit-eligibility constraints. The following concluding remarks are drawn for this study:

1. At the long-run hourly baseline (\$67/MWh delivered electricity, $\phi = 0.50$), gross LCOH is \$5.04/kg and Net LCOH is \$2.04/kg, which is \$0.34/kg above the \$1.70/kg benchmark; with the degradation-adjusted case, the reported parity-gap range is +\$0.34/kg to +\$0.64/kg.
2. The geometric viable fraction declines from $\Gamma_{\text{geom,annual}} = 0.775$ to $\Gamma_{\text{geom,hourly}} = 0.672$, corresponding to a 13.3% relative contraction in modeled viable operating space.
3. The system is electricity-dominated ($\kappa = 0.22$): a \$10/MWh delivered-electricity change shifts Net LCOH by \$0.55/kg, while a 20% electrolyzer capital-cost change shifts Net LCOH by only \$0.16/kg.
4. The system is also credit-dependent ($\Psi_{\text{credit}} = 0.59$): Tier 1 to Tier 2 downgrade imposes a \$2.00/kg penalty, and partial-credit cases remain above parity across the benchmark range reported.

5. Under realistic 45V-compliant operation, parity is feasible only in a narrow operating corridor; therefore, screening methods that ignore utilization and tier-risk effects can materially understate downside exposure.

For project developers, this framework provides a direct way to test go/no-go sensitivity to electricity price, capacity factor, and credit-tier risk. For policymakers and grid planners, the results show that compliance design and grid-operability measures must progress together to avoid creating unintended deployment bottlenecks. Recent federal changes that shorten 45V eligibility to facilities beginning construction before January 1, 2028 further increase the urgency of resolving electricity-procurement and utilization constraints during early project development windows [31, 32]. These results do not assess the probability of project success, but rather delineate the operational conditions under which parity is economically feasible.

For international deployment, the framework implies different constraint regimes by region. In EU import-sensitive markets (higher gray-hydrogen benchmark ranges), parity can be achieved earlier but remains exposed to credit continuity and electricity deliverability constraints. In MENA gas-rich contexts (lower benchmark ranges), parity pressure is tighter and project viability depends on very low delivered electricity plus high utilization discipline. In Australia-scale renewable corridors, strong resource quality can improve economics, but transmission distance, firming requirements, and water-security constraints can shift the feasible envelope unless addressed together in siting and infrastructure planning. Taken together, the results suggest that future clean hydrogen deployment success under 45V will depend less on marginal technology improvements and more on structurally aligned electricity procurement and durable policy design.

Future work should extend this framework with hourly dispatch optimization, location-specific renewable profiles, and degradation trajectories so that parity boundaries can be translated into site-specific bankability workflows. Specific high-priority extensions include: (1) integration with regional renewable-generation time-series data to compute Γ_w for key deployment corridors, (2) incorporation of electrolyzer degradation curves and stack-replacement economics over 30-year project lifetimes, and (3) coupling with end-use market models to assess hydrogen demand elasticity under varying delivered-cost scenarios.

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