Full-Chain Levelized Cost Assessment of Green Hydrogen: From Production to End-Use

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Abstract

This paper presents a full-chain techno-economic analysis of green hydrogen systems, extending beyond production to include storage, distribution, delivery, and end-use conversion. While most cost assessments rely on the Levelized Cost of Hydrogen (LCOH) at the production point, this approach does not account for the infrastructure and energy losses that occur downstream. To address this limitation, we introduce a five-part cost framework composed of LCOH, the Levelized Cost of Storage (LCOS), Distribution (LCOD), Delivery (LCODel), and End Use (LCOEU). Using current technology assumptions and cost parameters drawn from recent European Commission, DOE, and academic data, we model a representative system in which green hydrogen is used in stationary PEM fuel cells operating at 60% efficiency. Results show that while LCOH is 5.00 USD/kg, inclusion of storage, transport, and final delivery increases the upstream cost to 10.50 USD/kg. When end-use efficiency is incorporated, the effective cost of usable hydrogen energy rises to 17.50 USD/kg. This more than threefold increase illustrates how infrastructure requirements and energy conversion losses dominate the economics of delivered hydrogen. The analysis underscores the inadequacy of using LCOH alone as a basis for investment, policy design, or system evaluation. Instead, full-chain modeling provides a more accurate and transparent framework for identifying cost drivers, evaluating trade-offs, and comparing hydrogen systems to alternative energy carriers. The methodology presented supports decision-making across energy, transportation, and industrial applications where hydrogen is expected to play a growing role in decarbonization.

Keywords: Levelized cost of hydrogen; Green hydrogen; Hydrogen supply chain; Fuel cell systems; Techno-economic analysis

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1. Introduction

Hydrogen is increasingly positioned as a central pillar of global decarbonization strategies, with the potential to displace fossil fuels across a diverse array of sectors including steelmaking, heavy transport, energy storage, and chemical production. As an energy carrier, hydrogen offers key advantages: it produces no direct emissions at the point of use, can be synthesized using a variety of feedstocks, and is storable over long durations. Recognizing these attributes, governments and industry stakeholders have launched hydrogen roadmaps, subsidy programs, and infrastructure initiatives on an unprecedented scale. Yet, despite growing consensus around its importance, a critical question remains unresolved: How much will hydrogen actually cost the end user?

The most cited economic indicator is the Levelized Cost of Hydrogen (LCOH) defined as the total discounted cost of hydrogen production divided by the total discounted hydrogen output over the project lifetime. LCOH is useful for comparing production technologies (e.g., SMR, ATR, electrolysis) and evaluating sensitivities to electricity prices, capital expenditures, and capacity factors. For example, under baseline assumptions, green hydrogen produced via electrolysis currently exhibits LCOH values ranging from $3.50 to $6.00/kg, depending on electrolyzer efficiency, electricity cost, and project scale [1]. However, LCOH reflects only the cost of hydrogen at the point of production. It does not account for the additional costs incurred through storage, distribution, final delivery, and end-use conversion, each of which introduces additional capital and operational burdens, as well as energy losses.

This narrow focus has significant implications. In practical terms, hydrogen must be compressed, liquefied, stored, or chemically bound, then moved over long distances and ultimately delivered at the required pressure and purity to end users, who may convert it into electricity, heat, mechanical work, or chemical feedstock. Each of these downstream stages contributes to the final cost of hydrogen, which is often significantly higher than the production-only figure implied by LCOH [2].

To address this gap, this paper introduces and applies a full chain levelized cost framework that quantifies the cost of hydrogen from production to end-use. This framework includes five distinct metrics:

- **LCOH (Levelized Cost of Hydrogen)**: the cost at the production gate
- **LCOS (Levelized Cost of Storage)**: the cost to store hydrogen, accounting for tank costs, energy losses, and cycling
- **LCOD (Levelized Cost of Distribution)**: the cost to transport hydrogen to the point of use via pipelines, tube trailers, or ships
- **LCODel (Levelized Cost of Delivery)**: the cost of final dispensing, compression, and metering
- **LCOEU (Levelized Cost of End Use)**: the cost to the consumer, adjusted for system efficiency (e.g., fuel cells, turbines)

Each of these cost categories is interdependent and influenced by technology choice, infrastructure maturity, and operational scale. Importantly, improvements or inefficiencies in one stage can amplify or offset gains achieved [3] in another.

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For example, a green hydrogen project may achieve an LCOH of $5.25/kg through favorable electricity pricing and large-scale electrolyzer deployment [1]. However, when stored in high-pressure composite tanks (LCOS: $1.85/kg), transported via compressed gas trailers (LCOD: $2.50/kg), and dispensed through a small-scale refueling station (LCODel: $1.40/kg), the delivered cost reaches $11.00/kg. In a fuel cell vehicle operating at 55% efficiency [4], this results in a Levelized Cost of End Use (LCOEU) of approximately $20.00/kg-equivalent. Thus, the initial LCOH, while seemingly competitive, does not reflect the total burden placed on consumers or system operators.

Conversely, a project with a higher LCOH say, $6.00/kg but lower LCOS and LCOD (through improved tank design, higher utilization, or more efficient pipelines) [5] may achieve a similar or lower final delivered cost. This example illustrates a key finding: reductions in LCOH do not automatically result in lower consumer costs. In some cases, greater economic gains can be achieved by optimizing storage, distribution, or delivery infrastructure rather than the production process itself.

The implications are profound. Policies that subsidize hydrogen production such as the U.S. Inflation Reduction Act's Section 45V tax credit may drive investment in low-LCOH systems without ensuring that hydrogen becomes truly cost-competitive at the point of use. Likewise, project evaluations that benchmark only LCOH may misallocate capital by overlooking cost bottlenecks in the downstream value chain. For hydrogen to scale efficiently and equitably, decision-makers must adopt a system-level view one that considers the entire economic chain from production through delivery and consumption.

In this paper, we develop the mathematical definitions of each LC component, identify their key cost drivers, and present a unified framework for evaluating hydrogen's end-use cost in different market contexts. Drawing from peer-reviewed literature and techno-economic studies [1,3], we quantify how different configurations of hydrogen production, storage, transport, and use affect both the absolute and marginal cost of delivered hydrogen. We demonstrate that full-chain analysis not only enhances cost transparency but also reveals the most impactful levers for investment and policy intervention.

Ultimately, we argue that the viability of hydrogen systems particularly in early-stage markets with limited infrastructure and low utilization can only be assessed through a comprehensive, multi-stage cost model. The cost of hydrogen at the point of use, not the point of production, must be the benchmark for success.

2.1 Levelized Cost of Hydrogen (LCOH)

The levelized cost of hydrogen (LCOH) [1] is the principal metric used to assess the economic performance of hydrogen production facilities. It represents the minimum price per kilogram of hydrogen that enables the producer to recover the full cost of capital and operations over the project lifetime. While it is widely applied to compare production technologies including electrolysis, steam methane reforming (SMR),

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autothermal reforming (ATR), and pyrolysis only captures cost at the production facility boundary. As such, it provides a necessary but incomplete basis for evaluating the total economic feasibility of hydrogen systems, particularly in markets where distribution and end-use costs dominate the value chain.

Formally, LCOH is calculated using a discounted cash flow structure:

$$\mathrm{LCOH} = \frac{\sum_{t=1}^{T}\left(\frac{C_{\mathrm{CAPEX},t}+C_{\mathrm{OPEX},t}+C_{\mathrm{feedstock},t}}{(1+r)^t}\right)}{\sum_{t=1}^{T}\left(\frac{H_t}{(1+r)^t}\right)}$$

where CAPEX_t denotes the capital expenditure in year t, OPEX_t is the operational and maintenance cost, Feedstock_t is the cost of energy inputs (e.g., electricity or natural gas), H_t is the annual hydrogen output (in kg), r is the real discount rate, and T is the economic lifetime of the project (in years). In applied modeling, the capital term is typically annualized using a capital recovery factor (CRF), which simplifies the numerator and makes the LCOH formula analytically tractable across varied cost scenarios.

$$\mathrm{CRF} = \frac{r(1+r)^T}{(1+r)^T-1} \quad \Rightarrow \quad \mathrm{LCOH} = \frac{\mathrm{CRF}\cdot\mathrm{CAPEX}+\mathrm{OPEX}+\mathrm{Feedstock\ Cost}}{M_{\mathrm{H_2}}}$$

For green hydrogen via electrolysis, LCOH is dominated by electricity cost, electrolyzer capital intensity, efficiency, and system utilization. Curcio (2025) reports electrolyzer capital costs between \$1500 and \$2500/kW for small-scale (1–5 MW) systems, falling to \$800–1500/kW for 100 MW-scale deployments. Balance-of-plant costs including deionization, compression, cooling, and rectification decrease proportionally with system scale. Project lifetimes are typically assumed at 20 years, with real discount rates between 6–8%, resulting in CRFs of approximately 0.09–0.11 [1]. Electrolyzer efficiencies range from 60–70% LHV, with electricity consumption of 50–55 kWh/kg H_2. At \$30/MWh, this translates to a feedstock cost of \$1.65/kg, rising to \$2.75/kg at \$50/MWh, exclusive of CAPEX and OPEX contributions [5].

Scale is a critical determinant of LCOH. Capital costs per kilowatt decline sharply due to economies of scale in shared infrastructure (compressors, chillers, instrumentation) and reduced soft costs per unit. In addition, larger projects benefit from better procurement leverage and improved stack integration. Curcio (2025) shows that increasing plant size from 1 MW to 100 MW reduces CAPEX by over 45%, which in turn reduces LCOH by 20–30% depending on utilization [1]. Operating costs also improve with scale due to automation, staffing efficiency, and lower per-unit maintenance costs [6].

Utilization rate, or capacity factor, is equally influential. A 100 MW electrolyzer operating at 35% capacity factor will have the same fixed capital burden as one operating at 70% but will produce only half the hydrogen. As a result, LCOH increases non-linearly [1,6] at low utilization levels. In off-grid renewable configurations, capacity factors below 40% are common, especially for solar-only systems. Hybrid solar-wind or grid-tied projects can achieve 60–70% utilization, enabling much more favorable LCOH values. Curcio notes that increasing electrolyzer utilization from 35% to 60% reduces LCOH from over \$6.00/kg to under \$4.00/kg, holding electricity price and CAPEX constant [1].

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Electricity price is the single largest variable affecting green hydrogen LCOH. At an electrolyzer efficiency of 65%, each kilogram of hydrogen requires ~52 kWh of electricity. With wholesale electricity at $20/MWh, the feedstock component of LCOH is ~$1.04/kg; at $50/MWh, it exceeds $2.60/kg. These values exclude transmission charges, curtailment penalties, and dynamic pricing effects [7]. Projects sourcing electricity from behind-the-meter solar or wind can mitigate exposure to market volatility but typically trade this advantage for reduced utilization and higher curtailment.

Financing terms play a secondary but nontrivial role. A reduction in the discount rate from 7% to 5% lowers the CRF from 0.094 to 0.080 (over 20 years), reducing the annualized CAPEX burden by ~15%. Incentive mechanisms that affect financing such as concessional loans [8], production tax credits, or loan guarantees have direct consequences for LCOH. For example, under the U.S. Inflation Reduction Act (IRA), Section 45V offers production credits up to $3.00/kg for clean hydrogen meeting a <0.45 kg CO_2e/kg threshold, potentially halving LCOH for projects operating in eligible zones [1].

Geographic variability is substantial. In jurisdictions with abundant low-cost renewables (e.g., Australia, Morocco, Chile), levelized electricity costs can fall below $20/MWh, enabling LCOH below $2.50/kg under high utilization [1][2]. Conversely, in high-CAPEX regions with limited renewable access or poor utilization, LCOH may exceed $6.00/kg, rendering production uncompetitive absent aggressive subsidies or offtake guarantees.

Despite its importance, LCOH possesses inherent limitations that constrain its usefulness for system-level decision-making. First, it excludes all downstream costs, including compression, liquefaction, storage, distribution, and final delivery of which can match or exceed the production cost. In early-stage infrastructure settings, the combination of LCOS, LCOD, and LCODel can add $3.00–5.00/kg [1] to the consumer-facing cost, effectively doubling the value implied by LCOH alone. Second, LCOH assumes steady-state operation with idealized availability, ignoring real-world system outages, part-load penalties, and ramping losses, all of which degrade true output and raise effective cost per kilogram. Third, it fails to incorporate end-use conversion efficiency: a kilogram of hydrogen in a fuel cell delivers only ~55% of its lower heating value in usable energy, meaning the LCOH must be rescaled when comparing electricity, diesel, or natural gas on a service basis. Lastly, LCOH does not capture the cost of emissions compliance, lifecycle carbon intensity, or downstream decarbonization penalties factors increasingly central to offtake and eligibility in policy frameworks such as the EU Delegated Acts or the U.S. 45VH calculation [8-9]

In sum, while LCOH provides a rigorous benchmark for front-end techno-economic assessment, it cannot be used in isolation to determine competitiveness, affordability, or policy eligibility. It must be interpreted within a full-chain framework that accounts for system-wide costs and efficiency losses, which are addressed in the subsequent sections on LCOS, LCOD, LCODel, and LCOEU.

2.2 Levelized Cost of Storage (LCOS)

The Levelized Cost of Storage (LCOS) quantifies the average cost of storing one kilogram of hydrogen over the lifetime of a dedicated storage asset. It serves as the analog to the Levelized Cost of Hydrogen (LCOH), but applies specifically to capital- and energy-intensive infrastructure such as high-pressure tanks, cryogenic vessels, underground caverns, or chemical storage systems like LOHCs and ammonia. LCOS is a

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required component of full-chain hydrogen cost modeling, especially in sectors where hydrogen must be buffered, dispatched, or decoupled in time from the point of production [10,11]. Although structurally like LCOH, LCOS captures a distinct set of physical and economic processes and must be calculated independently using storage-specific input assumptions.

The LCOS is defined as:

$$\mathrm{CRF} = \frac{r(1+r)^T}{(1+r)^T - 1} \qquad \mathrm{LCOS} = \frac{\mathrm{CRF} \cdot \mathrm{CAPEX}_{\mathrm{storage}} + \mathrm{OPEX}_{\mathrm{storage}} + \mathrm{E}_{\mathrm{loss}}}{M_{\mathrm{retrieved}}}$$

Where CRF is the capital recovery factor, CAPEX is the total installed cost of the storage system, OPEX denotes annual operating and maintenance costs, E_{loss} is the annualized cost of energy or hydrogen losses during storage, and $M_{retrieved}$ represents the annual mass of usable hydrogen retrieved from the system. This formulation is consistent with that used in Curcio (2025) and is widely applied in techno-economic models of hydrogen refueling and bulk storage infrastructure [1].

Storage technology choice strongly influences the cost structure. For gaseous hydrogen stored at 350–700 bar, CAPEX typically ranges from 1200 to 2000 USD per kg of hydrogen capacity, with composite Type III or IV vessels requiring additional safety systems. OPEX is relatively modest but increases with system cycling frequency, ambient temperature swings, and pressure control complexity. Energy losses include recompression (typically 5–8% of LHV), thermal conditioning, and minor leakage. Round-trip energy penalties are approximately 10–15% for pressurized gas systems [1]. Under these assumptions, LCOS for high-pressure storage falls between 1.50 and 2.80 USD/kg H_2 retrieved at utilization rates above 60% and a 20-year asset life, assuming a 7% discount rate [12].

Cryogenic storage introduces higher CAPEX and significantly greater energy losses. Hydrogen liquefaction consumes 10–12 kWh/kg H_2, equal to 30–40% of its lower heating value, and daily boil-off ranges from 0.2% to 0.5% depending on scale and insulation. CAPEX for stationary cryogenic tanks typically ranges from 2000 to 4500 USD/kg capacity, while annual OPEX may exceed 100 USD/kg/year in small-scale or underutilized systems [1, 2]. Resulting LCOS values for liquid hydrogen storage commonly fall between 1.80 and 3.20 USD/kg H_2, with performance dominated by utilization rate and boil-off management [1].

Chemical hydrogen carriers such as LOHCs and ammonia offer storage in molecular form, with infrastructure and cost considerations distinct from physical storage. These systems incur high conversion losses, requiring dehydrogenation at temperatures exceeding 250°C or catalytic cracking. Reported round-trip efficiencies range from 35–55%, with CAPEX concentrated in reactor and heat recovery systems [2]. According to Ogunsola and Ogunsola, LOHC systems require 3.5–5.0 USD/kg H_2 in combined conversion, recovery, and energy input costs under typical assumptions [2,4]. While these carriers can co-optimize transport and storage, their LCOS values are typically noncompetitive unless deployed at very large scale with high asset utilization [10].

Geologic storage in salt caverns offers the lowest LCOS among all options, often under 0.50 USD/kg H_2 due to extremely low surface equipment requirements and negligible marginal operating cost [1]. However, such options are geographically limited and require site-specific prequalification, injection and withdrawal

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wells, and regulatory permitting. For centralized hydrogen hubs, geologic storage may play a major role; however, it is largely irrelevant to distributed or mobility-oriented hydrogen networks.

As with LCOH, system utilization is the dominant determinant of LCOS. High-throughput stations that cycle daily can amortize capital over a large hydrogen volume, reducing LCOS [11] substantially. At 20% utilization, LCOS may exceed 4.00 USD/kg H_2 even under optimal design conditions. Additionally, LCOS is sensitive to discount rates and system lifetime. A reduction in real discount rate from 7% to 5% lowers CRF from 0.0944 to 0.0802 (over 20 years), reducing the capital component of LCOS by more than 15% [1].

Despite its value, LCOS has inherent limitations. First, it assumes steady-state operation and neglects load variability, ambient effects, and ramping penalties. Second, LCOS [11,12] treats energy losses as exogenous costs rather than internal system inefficiencies, thereby decoupling them from upstream supply burdens. Third, it does not capture co-optimization opportunities with distribution or carrier systems, which may shift cost allocation across system boundaries. Finally, LCOS cannot be evaluated independently of LCOH or LCOD [1,10,12], as system-level performance and competitiveness depend on full-chain integration.

2.3 Levelized Cost of Distribution (LCOD)

The Levelized Cost of Distribution (LCOD) quantifies the average cost to transport one kilogram of hydrogen from the production site or storage terminal to the point of delivery, normalized over the infrastructure's economic lifetime. It captures the cost of distribution-specific infrastructure including pipelines, tube trailers, cryogenic tankers, compressors, and associated logistics and reflects both capital and operating expenditures incurred during transport. LCOD [11] is essential for full-chain hydrogen cost modeling and becomes particularly relevant in centralized production scenarios, regional hydrogen hub planning, and long-distance delivery schemes. Though mathematically analogous to LCOH and LCOS, LCOD reflects a physically distinct step in the hydrogen value chain and is sensitive to distance, transport mode, and scale.

The LCOD is defined as:

$$\mathrm{CRF} = \frac{r(1+r)^T}{(1+r)^T-1} \qquad \mathrm{LCOD} = \frac{\mathrm{CRF}\cdot\mathrm{CAPEX}_{\mathrm{distribution}} + \mathrm{OPEX}_{\mathrm{distribution}} + \mathrm{E}_{\mathrm{loss}}}{M_{\mathrm{delivered}}}$$

Here, CRF is the capital recovery factor; CAPEX represents the investment cost for distribution infrastructure; OPEX includes annual labor, maintenance, fuel, and leasing costs; E_{loss} refers to the annualized cost of energy or hydrogen lost during transport (e.g., boil-off, recompression); and $M_{delivered}$ is the annual quantity of hydrogen successfully delivered to the point of use. This structure is consistent with the approach defined in Curcio (2025) and supports direct integration with upstream (LCOH) and downstream (LCODel) cost components [1]. The choice of distribution pathway significantly affects LCOD. For compressed gaseous hydrogen delivered via tube trailers, CAPEX includes the cost of trailer fleets, trailer loading bays, high-pressure compressors, and safety systems. According to Curcio, capital costs typically range between 1200 and 1800 USD per kg/day of transport capacity for 350–700 bar systems, with OPEX costs around 0.80 to 1.50 USD/kg H_2 per 100 km roundtrip, depending on diesel prices, driver labor, and trailer utilization [1,2]. Gaseous transport is typically limited to 250–400 km due to payload constraints and the declining cost-efficiency at greater distances. For example, beyond 300 km, the cost per kilogram can exceed 2.00 USD even with full trailer utilization and optimized routing [10,12].

Cryogenic liquid hydrogen (LH_2) delivery offers higher volumetric density and longer range but imposes significant energy penalties during liquefaction and in-transit boil-off. Liquefaction requires 10–12 kWh/kg H_2, which translates to a capital and energy cost of 1.00–1.60 USD/kg H_2 even before transport. Tanker CAPEX is higher than for tube trailers due to insulation requirements, and OPEX includes refueling, cryogenic maintenance, and evaporation losses. LCOD values for LH_2 transport typically range from 1.40 to 2.40 USD/kg H_2, depending on distance, ambient temperature, and tanker size [1,5,8].

Pipeline distribution, where feasible, can offer lower LCOD [10,11] per kilogram for large and continuous flows. Hydrogen-specific pipelines cost approximately 1.0–2.0 million USD per km in greenfield projects, and operating costs include compression, inspection, and energy for pressure management. According to Curcio, LCOD values for dedicated hydrogen pipelines range from 0.70 to 1.50 USD/kg H_2 for distances between 50 and 200 km, assuming 100–300 tonnes/day throughput and 20-year project life [1,4]. Repurposing natural gas infrastructure can reduce CAPEX but requires hydrogen embrittlement mitigation and may be subject to pressure, purity, and blending constraints.

Distribution via chemical carriers, such as ammonia or LOHCs, involves additional synthesis and reconversion costs. However, for LCOD purposes, only the transportation-related infrastructure and energy use are counted. Ammonia transport by maritime tanker or rail adds approximately 0.30 to 0.60 USD/kg H_2 over 1000 km, while LOHC systems incur 0.50 to 1.00 USD/kg H_2 depending on turnover rates, carrier regeneration efficiency, and intermediate terminal costs [2,6].

As with other levelized cost metrics, utilization is a key driver of LCOD. Underutilized trailer fleets, idle loading bays, or low pipeline throughput inflate the capital component, resulting in sharp increases in LCOD. For example, a tube trailer network operating at only 30% of nameplate capacity may exhibit LCOD values 2–3 times higher than those of a fully utilized pipeline. Curcio (2025) reports that reducing average trailer fill from 90% to 60% increases unit transport cost by over 40%, all else held constant [1,2].

Despite its importance, LCOD has limitations [10,12]. First, it assumes fixed routing and excludes dynamic logistics optimization (e.g., real-time fleet routing or backhaul utilization). Second, it does not capture variability in weather-induced losses (e.g., cryogenic boil-off on hot routes) or urban congestion impacts on delivery time. Third, LCOD may not account for network interconnection costs, such as blending or pressure regulation stations required for pipeline injection. Finally, in systems where distribution and storage are physically integrated (e.g., cryogenic tankers with end-use fueling), LCOD must be carefully distinguished from LCODel and LCOS to avoid double counting.

2.4 Levelized Cost of Delivery (LCODel)

The Levelized Cost of Delivery (LCODel) represents the final stage of hydrogen transfer from distribution infrastructure into the point of use. Unlike hydrogen refueling stations which serve mobility applications

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and require high-pressure, high-speed, and thermally conditioned dispensing LCODel in stationary and industrial contexts refers to the cost of pressure regulation, final compression (where necessary), and controlled delivery into pipelines, fuel cell stacks, or reformer systems. These systems typically operate at moderate pressures (30–100 bar), do not require fast-fill protocols or precooling, and are characterized by stable, predictable demand profiles. As a result, the infrastructure required is simpler and less capital- and energy-intensive than mobility-based dispensing systems.

The LCODel is defined using the standard capital recovery formulation:

$$\mathrm{LCODel} = \frac{\mathrm{CRF} \cdot \mathrm{CAPEX}_{\mathrm{del}} + \mathrm{OPEX}_{\mathrm{del}} + C_{\mathrm{compression}}}{M_{\mathrm{H}_2}} \quad \text{with} \quad \mathrm{CRF} = \frac{r(1+r)^T}{(1+r)^T - 1}$$

Here, CAPEX_del includes delivery piping, control valves, safety systems, and final-stage compressors (if required); OPEX_del covers inspection, monitoring, and minor operational support; C_Compression represents the cost of energy consumed in raising pressure from transport levels (typically 20–30 bar) to application-specific operating pressure (typically ≤100 bar); and M_H2 is the mass of hydrogen delivered to the end-use interface per year. Because dispensing pressures are lower and utilization is more stable than in mobility systems, capital intensity is reduced and delivery energy is modest, typically below 2.0 kWh/kg H_2.

Based on current component pricing and electricity costs (~0.10 USD/kWh), total LCODel values for stationary applications typically range from 0.80 to 1.20 USD/kg H_2. Systems with integrated compressor skids and buffered flow control can achieve LCODel values closer to 0.90 USD/kg, particularly at steady flow rates above 200 kg/day. Unlike vehicle refueling infrastructure, these systems do not require precooling or fast-fill cascade systems, eliminating two of the largest capital cost drivers in high-pressure mobility stations. Furthermore, pressure staging is simpler, safety zoning requirements are lower, and maintenance is less intensive due to reduced cycling and flow variability[10,11].

LCODel is moderately sensitive to utilization. Under very low-throughput conditions (<50 kg/day), fixed capital costs dominate and levelized costs can exceed 1.50 USD/kg. However, in industrial or grid-connected microgrid configurations, hydrogen delivery tends to be continuous or cyclically predictable, enabling consistent utilization and efficient capital recovery. Compared to LCOS and LCOD, which are primarily driven by scale and distance, LCODel is governed by pressure requirements, energy input, and system integration cost [12].

It is important to distinguish this LCODel formulation from that used in mobility literature. Many published values reflect hydrogen refueling stations (HRS), where LCODel often ranges from 1.80 to 3.00 USD/kg due to compression to 700 bar, high-fill rate requirements, and mandatory precooling to –40°C. In contrast, stationary end-use systems operate below 100 bar and are not subject to these design constraints. The assumption of mobility-related LCODel figures in non-mobility modeling therefore leads to systematic overestimation of delivered hydrogen costs.

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In this framework, LCODel completes the upstream cost stack leading into end-use conversion. When added to LCOH, LCOS, and LCOD, it provides the total cost of hydrogen delivered at application interface conditions, prior to any energy transformation losses [6]. Accurate representation of this final delivery stage is essential for properly calculating LCOEU, and for identifying bottlenecks in small- to mid-scale hydrogen deployment outside of transport sectors.

2.5 Levelized Cost of End Use (LCOEU)

The Levelized Cost of End Use (LCOEU) represents the effective cost of delivered hydrogen per unit of usable energy or service output, accounting for conversion efficiency at the point of use. It closes the hydrogen value chain by integrating all upstream expenditures (LCOH, LCOS, LCOD, LCODel) with the performance of the final conversion device, such as a fuel cell, turbine, or hydrogen-compatible combustion engine. LCOEU is a critical metric for comparing hydrogen against conventional fuels, electricity, or alternative energy vectors on a delivered energy or cost-per-service basis (e.g., \$/kWh usable, \$/mile driven, or \$/kWhe).

The formal definition is:

$$\mathrm{LCOEU} = \frac{\mathrm{LCOH} + \mathrm{LCOS} + \mathrm{LCOD} + \mathrm{LCODel}}{\eta_{\text{end-use}}}$$

Where ηend-use is the net efficiency of the hydrogen conversion system at the point of use. This includes all energy losses associated with electrochemical, thermal, or mechanical conversion. The structure of the equation makes clear that even modest inefficiencies at the end-use stage can amplify total cost substantially, regardless of how low the upstream costs are.

Hydrogen fuel cells are the most efficient and adopted technology for hydrogen [9]. According to Curcio, modern polymer electrolyte membrane fuel cells (PEMFCs) exhibit system-level efficiencies between 58% and 62%, including parasitic loads for pumps, humidifiers, and controllers [1,2]. For stationary solid oxide fuel cells (SOFCs), electric efficiencies up to 65% are reported, rising to 80–85% when integrated with combined heat and power (CHP) systems [2,5,6]. In contrast, hydrogen internal combustion engines (ICEs) operate at lower efficiencies (~25–35%), and turbines exhibit 40–50% conversion efficiency depending on load and inlet pressure [1,2].

As an example, if total upstream costs sum to \$6.00/kg H_2 and the fuel cell efficiency is 60% (LHV basis), the LCOEU becomes:

$$\mathrm{LCOEU} = \frac{6.00}{0.60} = 10.00\ \mathrm{USD/kg\text{-}useful}$$

When normalized to delivered energy, this corresponds to ~\$0.30–0.40/kWh-useful, depending on hydrogen LHV (33.3 kWh/kg) and final use case. For comparison, diesel engines delivering equivalent

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energy cost $0.12–0.18/kWh, while grid electricity for industrial use ranges from $0.08 to $0.20/kWh, varying by region and sector.

Importantly, LCOEU is highly sensitive to load profile, partial-load operation, parasitic demand, and conversion degradation. Fuel cells operating below 25% of design load may exhibit efficiencies 10–15% below rated values due to membrane resistance and idle consumption. Similarly, ICEs and turbines lose efficiency rapidly at part-load due to incomplete combustion and thermal losses.

LCOEU is also affected by power electronics and thermal balance-of-plant (BoP). For example, stack-level PEMFC efficiency of 60% may degrade to 52–55% system efficiency after accounting for DC-DC converters, auxiliary blowers, and stack cooling loads. In CHP configurations, total energy utilization improves, but only when waste heat is productively captured and integrated.

Finally, LCOEU is essential for technology-neutral comparisons. A system with low LCOH (e.g., green hydrogen at $3.50/kg) may still yield a poor LCOEU if used in a low-efficiency ICE. Conversely, high upstream cost hydrogen may yield competitive LCOEU [8,10] if used in high-efficiency fuel cells or CHP systems. This reinforces the necessity of assessing full-chain costs in terms of net delivered energy, not just production cost per kilogram.

3. Conclusion: Integrated System Perspective: Full-Chain Cost Assessment of Green Hydrogen

The results in figure 1 illustrate the progression of hydrogen cost across the supply chain under current conditions. The base production cost (LCOH) is estimated at 5.00 USD/kg, representing the plant-gate price of green hydrogen generated via electrolysis. This value does not include the additional costs required to store, transport, and deliver hydrogen to the point of use. Including storage, distribution, and final delivery raises the upstream cost to 10.50 USD/kg. When this fuel is used in a PEM fuel cell operating at 60 percent efficiency, the levelized cost of usable hydrogen energy (LCOEU) increases to 17.50 USD/kg. The difference between the production cost and the cost at the point of use reflects the cumulative impact of infrastructure and conversion losses and illustrates the limitations of relying solely on LCOH as a basis for system evaluation or policy support.

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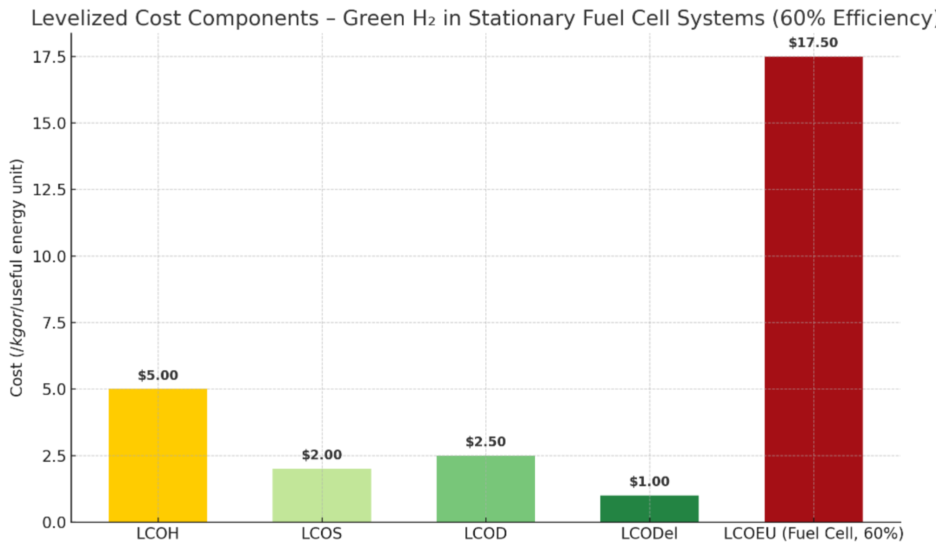

Fig.1: Levelized Cost Components

The LCOH forms the initial base of the cost structure at 5.00 USD/kg, but successive additions from LCOS (2.00 USD/kg), LCOD (2.50 USD/kg), and LCODel (1.00 USD/kg) raise the delivered cost to 10.50 USD/kg even before energy is consumed. The final LCOEU component, which incorporates the efficiency penalty associated with converting hydrogen into electrical power at the end-use device, increases the effective cost to 17.50 USD/kg at 60% fuel cell efficiency. This 7.00 USD/kg-equivalent loss reflects the thermodynamic cost of end-use conversion. While relatively modest for PEM fuel cells, this penalty can dominate the full-chain cost for low-efficiency systems such as turbines or ICEs, as shown in comparative LCOEU scenarios discussed earlier. The full-chain framework thus captures not only additive cost accumulation but also exposes the asymmetric impact of downstream inefficiencies and infrastructure underutilization on system economics.

From a techno-economic modeling perspective, two essential conclusions emerge. First, minimizing LCOH alone is insufficient and can produce misleading cost signals. As shown by Curcio (2025), the European Commission (2022), and Ogunsola (2025), downstream costs particularly for delivery, storage, and energy conversion can exceed production cost by 100–300% under real-world conditions [1,3]. Second, the interdependence of LC terms means that no single metric should be optimized in isolation. For example, reductions in LCOH through cheap electricity procurement have limited impact on LCOEU unless paired with downstream improvements in storage efficiency, delivery integration, or end-use system performance. In early-stage stationary systems with moderate utilization, LCOS and LCODel may dominate system costs, especially where infrastructure is overbuilt or poorly cycled.

These results have direct implications for both policy and investment. Policymakers frequently rely on LCOH benchmarks to define eligibility thresholds or incentive schemes. However, when such policies exclude full-chain costs, particularly amortized infrastructure and conversion inefficiencies, the resulting subsidy design fails to reflect the actual delivered cost of hydrogen. Similarly, developers and investors assessing hydrogen system feasibility must account for the entire value chain, from electrolyzer operation to system integration, rather than relying on optimistic production-only assumptions. A hydrogen system

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is only as competitive as its weakest cost segment, and omission of any chain component distorts both technical feasibility and economic outcomes. In conclusion, the figure and analysis presented confirm that system-level cost modeling is essential to evaluating green hydrogen beyond theoretical viability. Full-chain LCO analysis resulting in LCOEU offers a transparent and actionable basis for technology comparison, investment prioritization, and policy design. In stationary fuel cell systems operating at today's performance levels, the true delivered cost of usable green hydrogen is approximately 17.50 USD/kg more than triple the LCOH. To enable a competitive and decarbonized hydrogen future, stakeholders must move beyond production-centric narratives and adopt integrated cost modeling approaches that reflect infrastructure realities and end-use performance.

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