STRATEGIES FOR HARNESSING SURPLUS ENERGY FROM SMALL-SCALE HYDROPOWER IN LOCAL ENERGY COMMUNITIES: EVIDENCE FROM NORTHERN ITALY

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ABSTRACT

In the context of increasing renewable energy penetration and the growing challenge of managing non-programmable sources, hydropower remains a strategic asset for the energy transition. However, in decentralised systems such as local energy communities (LECs) or energy islands, surplus electricity cannot always be injected into the grid profitably or consumed immediately on-site, depending on the mix of local end-users. This study investigates a strategy for valorising surplus electricity through on-site green hydrogen production via water electrolysis, using the excess generation from a small-scale hydropower plant in northern Italy. A techno-economic methodology is applied, combining high-resolution energy analysis, the design of a proton exchange membrane (PEM) electrolyser system, levelized cost of hydrogen (LCOH) estimation, and net present value assessment under different feed-in tariff scenarios. Results indicate that the optimal PEM electrolyser capacity for the case study is 95 kW, requiring an additional 1 kW for hydrogen compression. This configuration produces 14,932 kg of green hydrogen annually, achieving an LCOH of €1.71/kg. The opportunity cost of electricity is excluded, as the energy used for electrolysis comes from surplus production with a marginal operational cost of €10/MWh, considered instead of the full market price. The analysis shows that a break-even feed-in tariff of €7.72/kg is needed to match revenues from electricity sales, while an incentive of only €4.20/kg is sufficient when hydrogen is sold at €5.00/kg. These thresholds are significantly lower than current equivalent incentives, highlighting the economic feasibility of the approach. The findings provide policymakers, LECs and energy islands with a practical decision-making framework to support the deployment of distributed green hydrogen systems, thereby enhancing renewable energy integration and utilisation.

Keywords: hydrogen, local energy communities, PEM electrolyser, renewable energy, small-scale hydropower.

1 INTRODUCTION

Hydropower remains a cornerstone of the global energy mix due to its low Greenhouse Gas (GHG) emissions and its crucial role in supporting the transition towards climate neutrality by 2050 [1]. In Italy, it accounts for 10.5% of total electricity generation and 41.2% of renewable output [2], offering a flexible and reliable source of power [3]. Nevertheless, the increasing penetration of variable renewable energy sources has intensified the challenge of managing surplus electricity, particularly within local energy communities and isolated microgrids [4]. In these contexts, unutilised excess energy represents not only an economic inefficiency but also a missed environmental opportunity.

Several studies have investigated strategies for valorising surplus renewable energy. In the hydropower sector, battery energy storage systems (BESSs) alone are unsuitable for seasonal storage, as shown by Jin et al. [5], who reported that achieving off-grid operation would require approximately 280 MWh of storage capacity at about €10,000/MWh, compared to 173 MWh of hydrogen storage at roughly €1,000/MWh. Converting surplus electricity into green hydrogen via electrolysis represents a promising alternative. Hydrogen

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offers a high-energy-density carrier with substantial commercial potential. In this context, Hussain et al. [4] demonstrated that integrating a photovoltaic-wind-BESS hybrid system with an electrolyser can reduce surplus electricity from 64.9% to 29% while producing more than 250 kg/year of hydrogen. Similarly, Al-Buraiki and Al-Sharafi [6] estimated that small-scale hydropower in southern Brazil could yield 5.95 million Nm^3/day of green hydrogen, confirming both the technical viability and economic attractiveness of converting surplus renewable energy into hydrogen.

To the authors' knowledge, despite growing interest in renewable hydrogen, very few studies have examined the feed-in tariff structures required to make small-scale green hydrogen production competitive with direct electricity sales, particularly in the Italian context. This research addresses this gap by delivering a techno-economic assessment of green hydrogen production from surplus electricity generated by a small-scale hydropower plant. The study identifies the feed-in tariff thresholds necessary to achieve economic parity with grid electricity sales, providing original insights for policymakers and stakeholders aiming to foster the deployment of decentralised hydrogen systems.

The remainder of this paper is organised as follows. Section 2 outlines the methodological framework for the techno-economic analysis, detailing the levelized cost of hydrogen (LCOH) calculation and the net present value (NPV)-based evaluation of incentive thresholds. Section 3 presents the case study, describing the small-scale hydropower plant in northern Italy and the associated data set. Section 4 reports and discusses the main results, comparing the profitability of hydrogen production with direct electricity sales under various feed-in tariff scenarios. Section 5 concludes the paper with key findings and offers policy and operational recommendations.

2 MATERIALS AND METHODS

This section outlines the methodology for assessing the techno-economic feasibility of producing green hydrogen from surplus electricity of a small-scale hydropower plant. It combines high-resolution surplus energy analysis, PEM electrolyser sizing, LCOH calculation, and NPV assessment under different feed-in tariff scenarios.

2.1 Data collection and processing

High-resolution surplus power data for 2024 were obtained from a small-scale hydropower plant in northern Italy, recorded at 15-minute intervals. The surplus power (P_{surplus}) was determined as the positive difference between generated ($P_{\text{generated}}$) and consumed power (P_{consumed}):

$$P_{\text{surplus}}(t)[kW] = \max\left(0,\ P_{\text{generated}}(t) - P_{\text{consumed}}(t)\right). \tag{1}$$

Hourly electricity market prices for the NORD zone were applied, accounting for the minimum price guarantee (PMG) mechanism [8].

2.2 Hydrogen system design and sizing

A PEM electrolyser was selected for its fast response when coupled with renewables and proven commercial maturity [9], [10]. Its capacity was determined from the average surplus power and its capacity factor (CF), the latter reflecting the operating profile of the small-scale hydropower plant under study:

$$\mathrm{CF} = \frac{\text{Surplus energy [kWh]}}{P_{\text{electrolyser}}\,[\text{kW}]\cdot 8760[\text{h}]} \cdot 100. \tag{2}$$

A compressor is used to reach the 30–70 bar storage pressure and sustain high electrolyser load, modelled with isentropic compression theory [11]. This range enables grid injection and meets requirements for industrial, mobility, and fuel cell applications [12], [13].

$$P_{\text{compressor}} = \dot{m}_{H_2}\left[\frac{kg}{s}\right] \cdot \frac{\gamma}{\gamma-1} \cdot R\,\left[\frac{kJ}{kg \cdot K}\right] \cdot T_1[K] \cdot \frac{\left(\left(\frac{p_2[Pa]}{p_1[Pa]}\right)^{\frac{\gamma-1}{\gamma}} - 1\right)}{\eta_{\text{comp}}} \tag{3}$$

where γ is the specific heat ratio and equal to 1.41, R the gas constant and equal to 4,124 J/kgK, T_1 the inlet temperature and equal to 293 K, η_{comp} the compressor efficiency and equal to 0.8, p_1 the electrolyser output pressure and equal to 30 bar, and p_2 the storage pressure and equal to 70 bar. The average hydrogen mass flow rate ($\dot{m}_{H_2}$) was then calculated as in eqn (4):

$$\dot{m}_{H_2} = \frac{H_2^{\text{annual}}\,[\text{kg}]}{\text{Operating Hours [h]}} \tag{4}$$

where the annual hydrogen production (H_2^{annual}) was calculated by dividing the energy available for electrolysis ($E_{\text{electrolysis}}$), i.e., the total surplus energy from the small-scale hydropower plant minus the energy required for hydrogen compression, by the electrolyser's specific energy consumption (SC) of 55 kWh/kg [14]:

$$H_2^{\text{annual}}\,[\text{kg}] = \frac{E_{\text{electrolysis}}\,[\text{kWh}]}{\text{SC}\left[\frac{\text{kWh}}{\text{kg}}\right]}. \tag{5}$$

The resulting mass flow rate was then divided by 3,600 to ensure consistency with SI units for power calculations. The hydrogen mass required for a 6-hour buffer storage (t_{autonomy}) was calculated using eqn (6), based on the electrolyser power ($P_{\text{electrolyser}}$) and the SC. Storage capacity was sized to provide 6 hours of autonomy, balancing technical flexibility and CAPEX [15], assuming a hydrogen density of 5.6 kg/m^3 at 70 bar [16].

$$m_{\text{buffer [kg]}} = \frac{P_{\text{electrolyser}}[\text{kW}]}{SC\left[\frac{\text{kWh}}{\text{kg}}\right]} \cdot t_{\text{autonomy}}[h]. \tag{6}$$

2.3 Economic analysis of the hydrogen system

CAPEX covered the costs of the electrolyser, compressor, and buffer storage, while OPEX included the costs of water supply and maintenance for all system components.

2.4 Operating expenditure calculation and LCOH calculation

Annual operating costs include three components. Energy costs are calculated using a marginal cost approach, which accounts for the additional operational expenses of using surplus energy (e.g., turbine wear, system losses, and extra maintenance) rather than the opportunity cost of direct electricity sales, considered separately in the feed-in tariff analysis. The economic viability of the hydrogen production system was assessed through the LCOH,

Table 1: Capital and operating cost assumptions for the hydrogen production system.

Parameter	**Value**
Electrolyser CAPEX	1,300 €/kW [17]
Storage cost	15,000 €/m^3 [18]
Compressor CAPEX	€1,000/kW [19]
Water consumption	9 kg H_20/kg H_2 [20]
Water cost	2.0 €/m^3 [21]
Energy marginal cost	10 €/MWh [22]
O&M cost	5% of CAPEX/year [23]

representing the average cost per kilogram of hydrogen over the project lifetime. LCOH incorporates total capital expenditure ($\text{CAPEX}_{\text{total}}$) and cumulative operational expenditure ($\text{OPEX}_{\text{total}}$), divided by the total hydrogen production (H_2^{total}) over the same period, as shown in eqn (7):

$$\text{LCOH}\left[\frac{€}{\text{kg}}\right] = \frac{\text{CAPEX}_{\text{total}}\,[€] + \text{OPEX}_{\text{total}}\,[€]}{H_2^{\text{total}}\,[\text{kg}]} \tag{7}$$

where both OPEX and hydrogen production are calculated over the entire project lifetime.

2.5 NPV analysis

To establish the baseline scenario, the residual operating cash flow (ROCF) from direct electricity sales to the grid was calculated. This represents the cumulative discounted revenue from selling the small-scale hydropower surplus over the entire project lifetime, without hydrogen production, and was determined using standard financial methodology [24]:

$$\text{ROCF} = (\text{AER}) \cdot \left(\frac{1-(1+r)^{-n}}{r}\right) \tag{8}$$

where AER (annual electricity revenue) is the total net income from selling the hydropower surplus to the grid at the hourly zonal price (PZO) over one year, the discount rate r is set at 4%, consistent with renewable energy sector standards, and n is the project lifetime in years. When calculating AER, the OPEX of the small-scale hydropower plant is excluded, as it would be incurred regardless of hydrogen production. Only the operating costs directly attributable to the hydrogen system are included in eqn (8). Dispatch costs (DP), set at 3%, represent market management fees [25] and are calculated as follows:

$$\text{AER}\left[\frac{€}{\text{year}}\right] = \left(\sum_{\text{year}} E_{\text{surplus}}(t)\ \left[\frac{\text{kWh}}{\text{year}}\right] \cdot \text{PZO}\,(t)\left[\frac{€}{\text{kWh}}\right]\right) \cdot (1-\text{DP}). \tag{9}$$

For hydrogen production scenarios, the net present value (NPV_{H_2}) was calculated by summing the discounted annual cash flows over the project lifetime and subtracting the initial investment, as expressed in eqn (10):

$$\text{NPV}_{H_2} = -\text{CAPEX}_{\text{total}} + \sum_{t=1}^{n}\frac{\text{Cash Flow}_t}{(1+r)^t}. \tag{10}$$

The annual cash flow represents the net economic benefit from hydrogen production each year, calculated as the annual hydrogen revenue ($R_{H_2}^{\text{annual}}$) minus the annual operating costs ($\text{OPEX}_{\text{annual}}$):

$$\text{Cash Flow}_t = R_{H_2}^{\text{annual}} - \text{OPEX}_{\text{annual}}. \tag{11}$$

Annual revenue is defined as the product of the annual hydrogen production and the unit sale price, given by the sum of the LCOH and the feed-in tariff incentive (FIT_{H_2}):

$$R_{H_2}^{\text{annual}} = H_2^{\text{annual}} \cdot \left(\text{LCOH} + \text{FIT}_{H_2}\right). \tag{12}$$

The model assumes hydrogen is sold at its production cost (LCOH), with profitability arising entirely from the public incentive mechanism. The break-even feed-in tariff was defined as the value required to achieve NPV parity with direct electricity sales over 15 years, matching the standard duration of the feed-in tariff scheme for newly installed small-scale hydropower plants in Italy:

$$\text{NPV}_{H_2} = \text{ROCF}. \tag{13}$$

The required feed-in tariff was calculated using eqn (14)

$$\text{FIT}_{H_2} = \frac{\text{ROCF}}{H_2^{\text{annual}} \cdot \text{TD}_{\text{factor}}} - \text{LCOH} \tag{14}$$

where $\text{TD}_{\text{factor}}$ represents the time-discounting factor for annual cash flows:

$$\text{TD}_{\text{factor}} = \frac{1-(1+r)^{-n}}{r}. \tag{15}$$

For competitive advantage scenarios, the same methodology was applied, but the NPV target was increased by a premium factor to ensure profitability beyond break-even. The target NPV was defined as the direct sales ROCF multiplied by (1+PF), where PF (premium factor) represents the desired percentage of competitive advantage.

$$\text{NPV}_{H_2} = \text{ROCF} \cdot (1 + \text{PF}). \tag{16}$$

The algorithm was realised in the Python environment using an object-oriented structure to ensure flexibility and clarity across different economic scenarios. The algorithm employs *pandas* for data processing, *numpy* for calculations, and *matplotlib* for visualisation, with results automatically exported for scenario comparison.

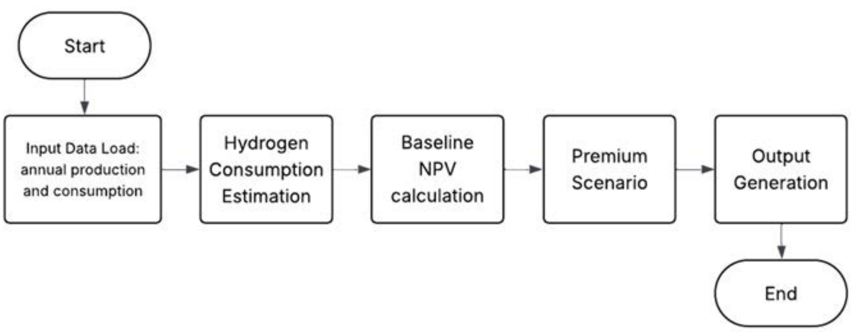

Figure 1: Techno-economic assessment flowchart.

3 CASE STUDY

The proposed methodology was applied using real data from a small-scale, run-of-the-river hydropower plant in northern Italy. Commissioned in 1985 and refurbished in 2006 to enhance operational reliability, the plant features an 80 m head and a 520 m penstock. It produces an average of 650 MWh per year, supplying electricity to five households, with the surplus fed into the local distribution network. The analysis used high-resolution operational data collected in 2024 at 15-minute intervals, enabling a detailed reconstruction of the surplus energy profile.

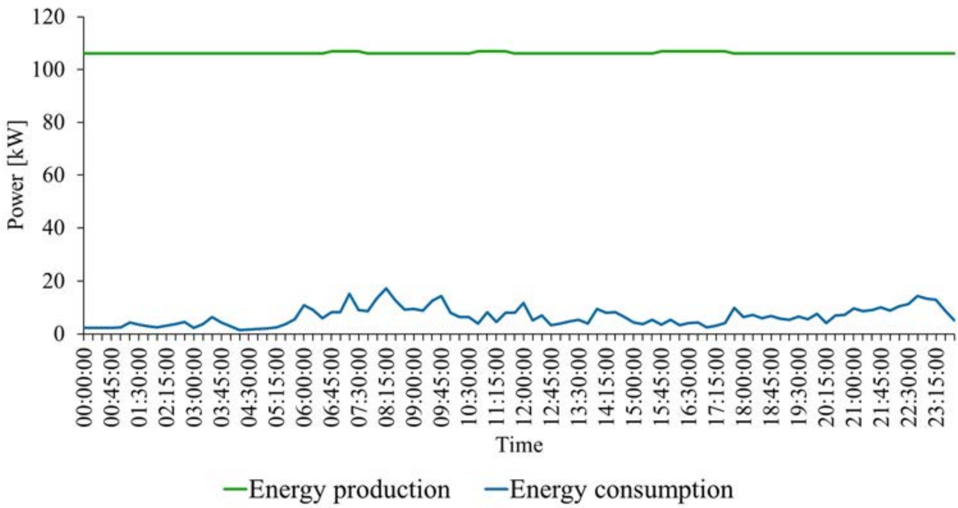

Figure 2: Energy production and consumption on a winter day (25/01/2024).

To utilise the energy surplus, a PEM electrolyser was chosen for its rapid response to variable input and proven commercial maturity [10]. System sizing followed the average-based method of Jovan et al. [9], assuming a specific energy consumption of 55 kWh/kg H_2 [14]. Compression from 30 to 70 bar, with an efficiency of 0.8 [26], was modelled using isentropic compression theory [11], and total hydrogen production was adjusted to account for compression energy losses.

Two economic scenarios were evaluated: (i) direct electricity sales at a PMG of €74.5/MWh [27] and (ii) hydrogen production with variable incentives. A NPV analysis was performed over a 15-year horizon, matching the feed-in tariff period for small-scale hydropower plants, using a 4% discount rate [28] and accounting for 3% shipping costs [25]. Hydrogen revenues were calculated as the sum of the LCOH and a public feed-in tariff, while the break-even incentive was determined by setting the NPV equal to that of electricity sales. Table 2 summarises the main technology cost assumptions for the case study.

4 RESULTS AND COMMENTS

Three scenarios were compared: (1) direct electricity sales under current PZO market conditions, (2) hydrogen production with a break-even incentive achieving NPV parity, and (3) hydrogen production with an enhanced incentive incorporating a premium factor for added competitiveness. The 2024 average peak surplus power from the small-scale

Table 2: Cost assumptions for the hydrogen production system components.

Parameter	Value
Electrolyser	123,500 €
Buffer	27,857 €
Compressor	1000 €
Discount rate	4% [28]
Project lifetime	15 years [29]
PMG threshold	74.5 €/MWh [27]

hydropower plant was 94.7 kW, supporting the selection of a 95 kW PEM electrolyser with a capacity factor of 98.7%. Assuming a specific energy consumption of 55 kWh/kg H_2, the annual hydrogen production averages 14,932 kg. The calculated LCOH is €1.71/kg, reflecting the marginal cost of surplus energy of 10 €/MWh. The cost breakdown includes 45.7% CAPEX, 32.4% energy, 20.8% O&M, and 1.1% water (see Fig. 3), confirming strong economic efficiency.

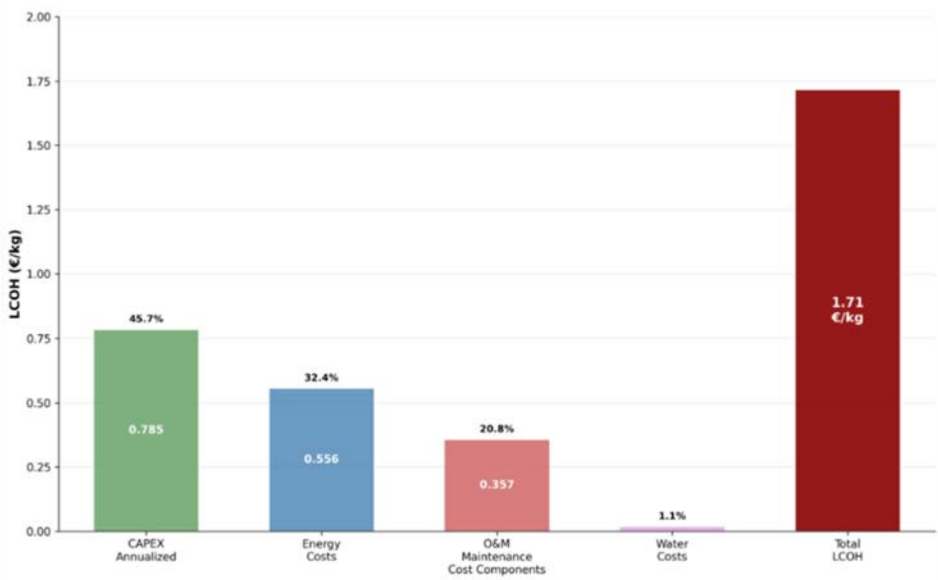

Figure 3: Breakdown of LCOH from small-scale hydropower surplus.

The 15-year ROCF for direct electricity sales is €970,546. To achieve parity, a feed-in tariff of €7.72/kg is required, resulting in an effective hydrogen price of €9.43/kg (LCOH plus incentive). If hydrogen is sold at €5.00/kg, the needed incentive drops to €4.43/kg, reducing public expenditure and improving market competitiveness. Although the full parity price remains well above conventional fuels like gasoline (€2.28/kg) and diesel (€1.98/kg), the lower incentive scenario brings green hydrogen closer to these benchmarks, narrowing the gap while limiting fiscal impact [30]. For a 10% competitive advantage (NPV target €1,047,407), incentives rise to €8.31/kg (LCOH-based sale) or €4.89/kg when hydrogen sells at €5.00/kg (see Fig. 4).

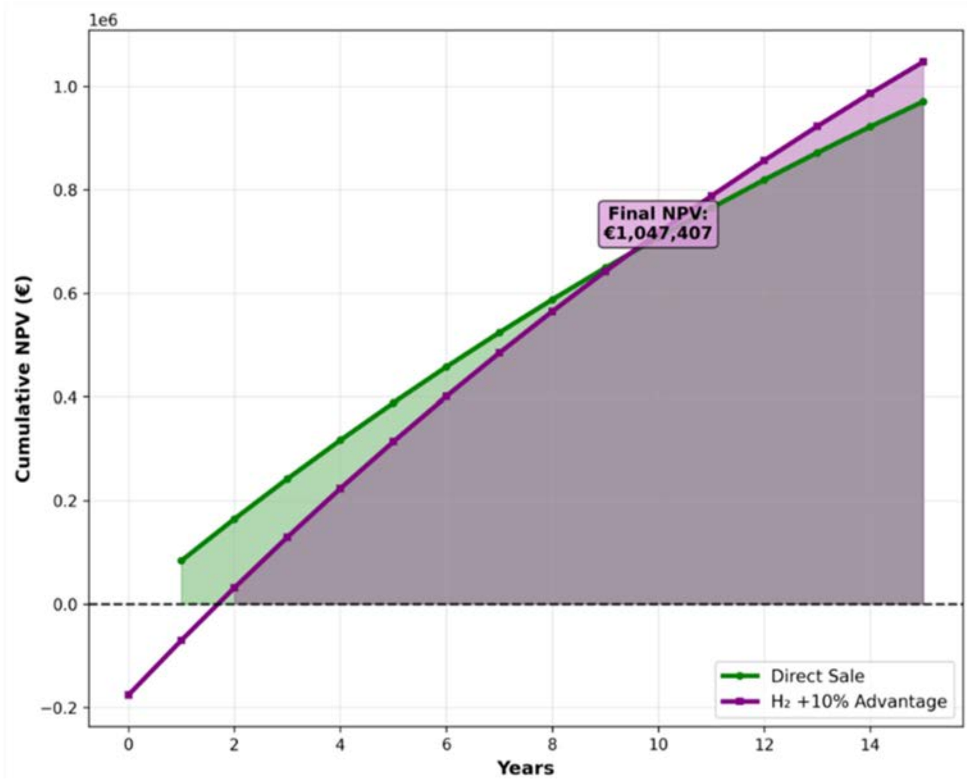

Figure 4: Hydrogen NPV with 10% advantage vs. direct sale (€1,047,407).

5 CONCLUSIONS

This study presents a robust methodology for valorising surplus energy from small-scale hydropower plants through on-site green hydrogen production, with particular applicability to LECs. By converting excess electricity into a storable and marketable energy carrier, the approach offers practical solutions for plant operators and community energy planners to enhance self-consumption, reduce curtailment, and improve the economic sustainability of renewable installations.

Applied to a real case study in northern Italy, a run-of-the-river, small-scale hydropower plant with an 80 m head, a 520 m penstock, and an average annual generation of 650 MWh supplying five households, the analysis confirms the techno-economic feasibility of a properly sized PEM electrolyser system for hydrogen production from surplus power.

The study identifies a break-even feed-in tariff of €7.72/kg to achieve revenue parity with direct electricity sales, while a more realistic hydrogen selling price of €5.00/kg reduces the required public incentive to approximately €4.43/kg. This translates to a hydrogen cost approaching that of conventional fuels such as gasoline and diesel, though still above Liquid Petroleum Gas (LPG) and ethanol prices. Importantly, achieving a 10% economic advantage with incentives below the national feed-in tariff equivalent appears feasible, providing a viable margin to offset upfront capital costs and attract investors.

These findings underscore the critical role of targeted incentive programs in accelerating the adoption of decentralised hydrogen production. Policymakers should consider structuring feed-in tariffs or premium mechanisms that balance fiscal responsibility with sufficient returns to stimulate market interest. Incentive schemes calibrated to offer moderate yet meaningful profitability, around 10% above break-even, can effectively promote green hydrogen as a flexible energy vector, facilitating higher renewable energy integration without imposing excessive public expenditure.

To maximise impact, policy frameworks should also support streamlined permitting, encourage synergies within LECs, and promote awareness among stakeholders about hydrogen's strategic value. By aligning incentives with real techno-economic conditions, regulators can foster an enabling environment where decentralised hydrogen production complements renewable generation, contributing to climate goals and energy system resilience.

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