

Where the Energy Goes in Green Hydrogen Production — and Where Optimisation Pays

Technical report for green hydrogen and energy optimisation service

Scope Water-electrolysis plants (alkaline, PEM and solid oxide), from the electricity import meter to hydrogen storage

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Basis Published research, technical literature and engineering synthesis

Central finding

In alkaline and PEM plants, most electricity that does not become hydrogen leaves the stack as low-grade heat, because practical cell voltages sit well above the 1.48 V thermoneutral voltage. Conversion, auxiliary, standby and compression losses are modest at rated load but grow at low load and as stacks age. Because electricity price and utilisation dominate cost per kilogram, optimisation pays most where it lowers system kWh/kg at real operating points without sacrificing operating hours.

Engineering note

This is a mechanism-based report, not a substitute for electrolyser OEM performance data and guarantees, site-specific design and integration studies, or process-safety review, including gas-purity protection and hazardous-area assessment.

Executive summary

Splitting liquid water needs at least 1.23 V of electrical work at standard conditions; voltage above the 1.48 V thermoneutral value is released as heat. By Faraday's law, stack consumption $\approx 26.6 \times V_{\text{cell}} \div \eta_{\text{F}}$ kWh/kg (η_{F} : faradaic efficiency), so each 0.1 V per cell costs about 2.7 kWh/kg.

US DOE status figures for 2022 put alkaline and PEM stacks at 1.9 V per cell and 51 kWh/kg, and complete systems at 55 kWh/kg, or 61% on a lower-heating-value basis [2,3]; the stack therefore accounts for most of the loss. Published 2020 system ranges are much wider, 50–83 kWh/kg [1], partly reflecting different boundaries and operating points.

Electricity is the largest single cost of on-site green hydrogen, but investment cost dominates at low operating hours [1]. Efficiency and utilisation must therefore be optimised together and, in the UK, alongside carbon intensity calculated per 30-minute reporting unit [12].

Table 1. Where energy is used or lost, from meter to storage

Stage	Mechanism	Impact	Optimisation lever
Power conversion (transformer, rectifier)	AC/DC losses; harmonics and low power factor at low load [8]	Specified efficiency >94% now, >98% in future [8]; very low at low load [1]	Topology matched to duty; staged rectifier-stack modules
Electrolysis stack	Voltage above 1.48 V becomes heat; crossover lowers faradaic efficiency	Largest loss; stack uses 51 of 55 kWh/kg at 2022 status [2,3]	Current density; temperature control; stack upgrades
Part load and standby	Fixed loads, supply losses and gas impurity grow relative to output	Alkaline part-load range limited by gas impurity [6]	Minimum-load and standby policy; staging; buffering
Degradation over life	Voltage rises at constant current	4.8 (PEM) and 3.2 (alkaline) mV/kh at 2022 status; end of life at 10% voltage rise [2,3]	Voltage trending; water quality; replacement timing
Balance of plant	Water treatment, cooling, deoxidation and drying	Water purification <USD 0.01/kg [1]; heat ≈20–30% of stack input over life in one PEM case [9]	Variable-speed cooling; heat recovery; purity matched to use
Compression	Raising pressure for storage or transport	1–30 bar ≈3.5–4% of LHV [1]	Pressurised output; staging; matched turndown
Storage and delivery	Further compression, liquefaction, leakage	Liquefaction 10–13 kWh/kg in practice [4]	Storage form matched to end use; leak detection

Source: engineering synthesis from [1]–[4], [6], [8], [9]. Values indicate magnitude under the cited conditions, not guarantees.

Priority actions

1. Define the measurement boundary and meter AC import, rectifier DC output, major auxiliaries and delivered hydrogen on one time base.
- (2) Measure system kWh/kg across load, including standby.
- (3) Trend stack voltage at reference current and temperature.
- (4) Optimise minimum load, standby, buffering and sizing against electricity cost, utilisation and the applicable carbon calculation.
- (5) Screen heat recovery against coincident site demand before investing.

Conclusions at a glance

- **Stack voltage:** the dominant loss; compare cell voltage at stated current density, temperature and age.
- **Outside the stack:** conversion and auxiliary losses are modest at rated load but grow at low load.
- **Utilisation:** at low operating hours the capital charge dominates; small efficiency gains rarely justify lost hours.
- **Degradation and compression:** manage degradation through replacement timing; pressurised output avoids the low-pressure stages, which cost the most energy per bar.
- **Heat and carbon:** heat pays only where demand is close and coincident; lower kWh/kg widens the carbon-compliance margin.

1. Energy basis and KPIs

1.1 Reference values

Basic thermodynamics gives four reference points:

- **Reversible voltage, 1.23 V** (25 °C, 1 bar): the minimum electrical work, ≈32.7 kWh/kg.
- **Thermoneutral voltage, ≈1.48 V** for liquid water: the reaction enthalpy, equal to the higher heating value (HHV); about 1.29 V for steam [7].
- **Heating values:** lower heating value (LHV) ≈33.3 kWh/kg (≈120 MJ/kg); HHV ≈39.4 kWh/kg (≈142 MJ/kg).
- **Faraday's law:** ≈26.6 kWh of charge per kilogram of H₂.

At 1.9 V and full faradaic efficiency, stack consumption is about 50.5 kWh/kg, consistent with DOE's 51 kWh/kg, which includes a crossover allowance [2]. About 22% of that input, $(1.9 - 1.48) \div 1.9$, becomes heat for the cooling system.

1.2 Stack versus system; LHV versus HHV

Stack specific energy consumption (SEC) divides DC stack energy by hydrogen produced; system SEC divides AC import energy, including conversion and auxiliaries, by hydrogen delivered at stated purity and pressure. Efficiency is heating value ÷ SEC: 55 kWh/kg is 61% on an LHV basis [2] but about 72% on an HHV basis. The UK government's 2021 cost study assumed 2020 whole-plant efficiencies of 77% (alkaline) and 72% (PEM) on an HHV basis, excluding compression [11], roughly 51 and 55 kWh/kg. Guarantees should state boundary, basis, pressure, purity, load point, averaging period and stack age.

1.3 KPIs and failure signatures

KPI	Primary indicators	Failure signature
Stack SEC (DC)	Cell and stack voltage at reference current density and temperature	Voltage rising at constant conditions; cell spread widening
System SEC (AC)	Import kWh/kg at stated purity and pressure, by load band	Gap to stack SEC widening at part load
Faradaic efficiency	Measured ÷ theoretical H ₂ from DC current	Falling at low load or high pressure; rising H ₂ -in-O ₂
Power conversion	Efficiency, power factor, harmonics, ripple	Deterioration at low load
Auxiliaries and standby	Sub-metered kWh/kg; kWh per standby hour	Fixed loads dominating at low output
Degradation	mV/kh at reference conditions	Rate accelerating after duty or water-quality changes

Source: synthesis from [1]–[3], [6], [8]; align definitions with OEM guarantee terms.

2. Electrolyser technologies and their energy characteristics

Table 2. Energy-relevant characteristics by technology

Characteristic	Alkaline	PEM	Solid oxide
Operating temperature [1]	70–90 °C	50–80 °C	700–850 °C
System SEC, 2020 range [1]	50–78 kWh/kg	50–83 kWh/kg	45–55 kWh/kg
2022 status: current density at 1.9 V; stack/system SEC [2,3]	0.5 A/cm ² ; 51/55 kWh/kg	2.0 A/cm ² ; 51/55 kWh/kg	Not covered
Stack lifetime, 2020 [1]	60,000 h	50,000–80,000 h	<20,000 h
Dynamic behaviour	Part-load range limited by gas impurity [6]	Preferred for dynamic duty: short start-up, broad load range [6]	Fast ramping when hot; limited thermal cycles [7]

Source: [1]–[3], [6], [7]. Values differ in date, scale and boundary; they are not like-for-like.

PEM matches alkaline consumption at four times the current density [2,3], needing less active area but iridium-bearing anodes [2]. PEM can run at differential pressure, typically 30–70 bar [1], reducing compression, though higher pressure increases hydrogen permeation [1]; alkaline gas impurity also rises with pressure [6]. Solid oxide electrolyzers (SOEC) need less electricity because part of the energy arrives as heat in the steam: systems should operate near the thermoneutral potential, and heat from exothermic downstream synthesis can raise the steam [7]. Heat should be counted as an input with its own cost and carbon intensity. Most reported SOEC stack tests now show degradation below 1% per 1,000 h [7], against 0.25% for DOE's 2022 PEM status [2].

3. Power supply and operating strategy with variable renewable electricity

3.1 Capacity factor versus cost

The levelised cost of hydrogen (LCOH) has two dominant terms: electricity cost per kilogram ($\text{SEC} \times \text{price}$) and the capital charge per kilogram ($\text{annualised capital and fixed costs} \div \text{output}$). IRENA notes that investment cost dominates at low operating hours, electricity dominates as hours increase, and about 3,000–4,000 hours per year may achieve the largest reduction in the investment contribution [1]. In the UK government's 2021 study, cutting load factor to 15% raised LCOH more than raising it to 35% lowered it, and free curtailed electricity at around 25% load factor left fixed costs dominant [11]. Sizing and real-time dispatch against prices and renewable output are therefore central design variables [10].

3.2 Ramping, minimum load and standby

At lower current density, cell voltage falls and stack efficiency improves, yet system SEC can worsen: power-supply losses become large at low load [1], fixed auxiliary loads are spread over less hydrogen, and gas crossover continues while production falls. In alkaline systems, impurity rises at low current density, with emergency-shutdown limits at 2 vol% hydrogen in oxygen [6], which sets the practical minimum load. The turning point is plant-specific and must be measured.

Hot SOEC stacks can ramp from zero to 80% load within milliseconds, but ceramic-supported stacks tolerate only about 150 thermal cycles [7]; balance of plant such as compressors, rather than the stack, often limits flexibility [1]. Load range, load gradients, start-up time and standby losses should be specified explicitly [5], and hot or cold standby chosen from measured standby energy and idle durations.

3.3 Buffering with batteries or hydrogen storage

A battery can bridge short dips, holding the electrolyser above minimum load, but adds capital cost and round-trip losses and cannot cover long lulls. Hydrogen storage decouples production from offtake, letting the electrolyser follow cheap or low-carbon electricity, at the cost of compression energy and storage capital. Dispatch modelling with measured profiles should decide between them [10].

3.4 Power quality

Thyristor rectifiers at large firing angles, typical of low-power operation, produce more harmonics and a lower power factor [8]. Converter requirements tabulated by Chen et al. include efficiency above 94%, power factor above 0.90 and current distortion below 5%, with future targets of 98%, 0.99 and ripple of 5% or less [8]; high ripple lowers efficiency [6]. Staged rectifier-stack modules can outperform one large unit at deep turndown.

4. Balance of plant and compression

4.1 Water, cooling, purification and drying

Stoichiometry requires 9 kg of water per kilogram of hydrogen; with demineralisation and process inefficiencies, consumption is typically 18–24 kg/kg, and purification costs less than USD 0.01/kg of hydrogen [1]. Water quality matters for reliability rather than energy, because impurities have a major impact on stack lifetime [1].

Cooling must remove the stack input not stored as chemical energy, about 20% at start of life and about 30% after ten years in one modelled PEM case [9], so degradation also raises cooling loads. Deoxidation, purging and dryer-regeneration losses are design-specific; vendor figures should be verified in operation.

4.2 Compression

For an ideal gas compressed isothermally, work scales with $\ln(p_2/p_1)$: compressing from 1 to 30 bar takes the same ideal work as from 30 to 900 bar. Delivering hydrogen at pressure therefore removes the most expensive compression per bar.

Table 3. Indicative energy for compression and liquefaction

Duty	Basis	Energy
1 → 30 bar	Estimate for atmospheric alkaline output [1]	≈3.5–4% of LHV (≈1.2–1.3 kWh/kg)
20 → 350 bar	Theoretical isothermal [4]	1.05 kWh/kg
20 → 700 bar	Theoretical isothermal [4]	≈1.36 kWh/kg (≈4% of LHV)
To 350 bar	Measured at on-site-production refuelling stations [4]	1.7–6.4 kWh/kg; 2–4 kWh/kg excluding outliers
Liquefaction	Operating plants [4]	10–13 kWh/kg (30–40% of LHV)

Source: [1], [4]. Station data were compiled in 2009 from refuelling-scale equipment.

IRENA estimates a compressor of about 4 MW for a 100 MW atmospheric electrolyser delivering 30 bar [1]. Because recycle and bypass waste energy when output varies, compressor turndown and buffer volume should match the electrolyser profile.

5. Heat recovery and site integration

Table 4. Recoverable heat by technology

Technology	Heat level	Plausible site uses	Constraint
Alkaline	Below the 70–90 °C operating range [1]	Space and district heating; process and feed-water preheat	Low grade; heat pump for higher temperatures
PEM	Below the 50–80 °C operating range [1]; 54 °C delivered in one modelled case [9]	Low-temperature heating networks; washing; preheating	Value falls sharply with upgrading or distance [9]
Solid oxide	700–850 °C operation [1]	Net heat consumer: steam from exothermic synthesis [7]	Heat import, not export, is the question

Source: [1], [7], [9]; site uses are engineering inference.

In a modelled 2.5 MW PEM installation, 14–15% of stack electricity could be used by a heat consumer, raising average ten-year efficiency from 76% to 90% (HHV) [9]. Using a heat pump to reach 100 °C roughly quadrupled the heat's levelised cost, heat transport was feasible only over about 1–3 km depending on use case, and even with buffering not all heat could be used [9]. Recovery pays where low-temperature demand is close, coincident and otherwise met by purchased energy. Oxygen, about 8 kg per kilogram of hydrogen, is a further by-product to evaluate.

6. Techno-economics: levelised cost of hydrogen drivers

In simplified form, $LCOH \approx (\text{annualised capital} + \text{fixed O\&M}) \div \text{output} + SEC \times \text{electricity price} + \text{stack replacement} - \text{by-product credits}$. Installed electrolysis capacity doubled in 2025 to surpass 4 GW, yet the IEA expects fossil-based production to remain less costly than renewable hydrogen in most regions in the near term [13]. IRENA notes that a power cost translates into roughly 1.5 times that value in hydrogen production cost [1].

Table 5. Principal LCOH drivers and sensitivities

Driver	How it enters LCOH	Sensitivity and evidence
Electricity price	$SEC \times \text{price}$	Largest single component [1]; UK price sensitivities moved LCOH by up to £22/MWh (HHV) for a 2030 plant [11]
Utilisation	$\text{Capital and fixed costs} \div \text{output}$	Investment dominates at low hours [1]; response to load factor is asymmetric [11]
System SEC	Multiplies electricity cost	At 55 kWh/kg, each 1 kWh/kg is $\approx 1.8\%$ of consumption [2]
Capital and stack replacement	Annualised capital; periodic stacks	2021 UK assumptions: stacks 50–60% of plant capital, replaced every 7–11 years [11]
Heat and oxygen	By-product credits	Site-specific [9]

Efficiency projects should therefore be valued at the electricity price in the hours the plant runs.

7. Carbon intensity and standards

The UK Low Carbon Hydrogen Standard (LCHS), published by the Department for Energy Security and Net Zero, sets a method for calculating hydrogen-production emissions and a threshold for hydrogen to count as low carbon [12]. Version 4 (January 2026) is used to assess eligibility under the Hydrogen Production Revenue Support (Directions, Eligibility and Counterparty) Regulations 2023; supported projects follow the version named in their agreement [12]. For electrolytic hydrogen:

- **Threshold:** no more than 20 gCO₂e/MJ of hydrogen product, LHV basis [12].
- **Boundary:** “point of production”, covering Scope 1, Scope 2 and partial Scope 3 emissions, including compression and purification to the Standard’s minimum pressure and purity, and input materials such as water [12].
- **Time resolution:** emissions are allocated to consignments within 30-minute reporting units, optionally aggregated monthly into weighted-average consignments [12].
- **Electricity:** generators supplying through eligible PPAs must show temporal correlation in each reporting unit; other grid electricity uses delivered intensities from the Data Annex, with a separate intensity for curtailment evidenced by a Bid Offer Acceptance [12].
- **Other conditions:** an eligible pathway, monthly reporting, a fugitive hydrogen emissions risk reduction plan and annual report, and a data collection and monitoring procedure [12].

As arithmetic only, 20 gCO₂e/MJ × ≈120 MJ/kg ≈ 2.4 kgCO₂e/kg. At 55 kWh/kg [2], electricity averaging about 44 gCO₂e/kWh would use the entire allowance; at 50 kWh/kg, about 48 g/kWh. This is not a compliance calculation, but it shows why efficiency, utilisation and half-hourly timing are coupled.

8. Optimisation and monitoring programme

8.1 Minimum data package

Category	Measurements	Decision supported
Electrical	AC import; rectifier input and output; stack DC current and voltage; power quality	Conversion losses; module staging
Stack	Cell or cell-group voltages; temperatures; pressures; hours and starts	Voltage efficiency; degradation
Gas	H ₂ mass flow; purity; O ₂ -in-H ₂ and H ₂ -in-O ₂ ; dew point	Faradaic efficiency; minimum load; purification loss
Auxiliaries and compression	Sub-metered cooling, water, purification, drying, HVAC and compressor energy	Fixed-load reduction; compression SEC
Water and heat	Water flow and conductivity; heat rejected and recovered	Water quality; heat integration
Commercial and carbon	Half-hourly prices and grid intensity; PPA generation data	Dispatch; LCHS consignment results

Agree metering accuracy and sampling with the OEM and any scheme’s monitoring procedure.

8.2 Study sequence

1. **Boundary and metering audit:** close the energy balance from import meter to storage.

2. **Baseline:** system SEC–load curve including standby; stack voltage–current curve at reference temperature.
3. **Classify the limiting loss:** stack voltage, part load and standby, conversion, auxiliaries, compression or utilisation.
4. **Model operating strategy** and by-product use with measured price, generation and demand profiles.
5. **Trial changes one at a time**, then confirm.

8.3 Acceptance criteria

Trial phase	Controlled change	Acceptance criteria
A. Baseline	None; establish variability	Energy and mass balances close within an agreed tolerance
B. Operating set-points	Minimum load, standby or staging within the OEM envelope	Lower normalised system kWh/kg without purity, trip or degradation penalty
C. Equipment	Rectifier, auxiliary, heat-recovery or compressor change	Normalised saving matches the business case; no availability loss
D. Confirmation	Repeat best condition or return to baseline	Improvement reproducible beyond baseline variation; carbon result compliant

Changes require management-of-change and process-safety review.

9. Trade-offs

Control knob	Potential benefit	Principal trade-off
Current density	Lower cell voltage and stack SEC	More capital per kilogram
Output pressure	Less downstream compression	Higher crossover and gas impurity [1,6]
Minimum-load set-point	More hours on variable supply	Gas-purity margin; part-load efficiency [6]
Hot versus cold standby	Fast restart versus no standby energy	Energy without output versus thermal cycling
Battery buffer	Fewer trips; minimum load maintained	Capital cost; round-trip losses
Hydrogen storage	Production decoupled from offtake	Compression energy; storage capital
Electrolyser-to-supply sizing	Higher utilisation or more low-cost power used	Capital per kilogram versus unused supply [10]
Stack replacement timing	Restores voltage efficiency	Replacement capital and downtime
Heat recovery	By-product value; site fuel savings	Pipework, heat pumps, intermittency [9]

10. Conclusions

In alkaline and PEM plants, stack voltage governs most of the energy that does not become hydrogen. Losses outside the stack rise at low load, where plants on variable supply can spend much of their time, and degradation slowly raises kWh/kg and cooling duty. Because electricity price and utilisation dominate levelised cost, efficiency measures should be judged on cost and carbon together in the hours the plant actually runs.

Recommended decision rule

Before investing, establish which loss limits the plant over its actual operating profile. If system kWh/kg tracks stack kWh/kg, focus on cell voltage, temperature and degradation; if the gap widens at low load, on conversion, auxiliaries, standby and minimum load. If the capital charge dominates cost per kilogram, prioritise utilisation over marginal efficiency. Recover heat only where demand is near and coincident.

References

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Evidence limitations

- DOE status values and the UK government’s 2021 cost assumptions are generic and dated; they indicate magnitude, not product performance.
- Compression data come from a 2009 analysis of refuelling-scale equipment.
- Heat-recovery evidence rests on one modelled Dutch PEM case.

- SOEC evidence comes largely from cell, stack and demonstration testing.
- No generic values were found for purification, drying or standby losses.
- The LCHS is version-controlled; this report reflects version 4 (January 2026).