Gold Standard for the Global Goals

METHODOLOGY – SUPPLEMENTARY INFORMATION

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SDG 13

SUPPLEMENTARY INFORMATION: GREEN HYDROGEN PRODUCTION

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SUMMARY

This Supplementary Information document supports the Gold Standard methodology for Green Hydrogen Production (GS4GG PAA M400-02). It provides a comprehensive technical and contextual foundation to guide methodology implementation and verification. The document analyses green hydrogen's market trajectory, potential climate impact, lock-in risks, technology benchmarks, and baseline-setting approaches, offering evidence-based recommendations for establishing robust methodological parameters.

It is intended for use by methodology developers, project proponents, host country authorities, and Validation and Verification Bodies (VVBs) seeking to understand the strategic relevance and design considerations for green hydrogen projects under climate crediting mechanisms.

READER GUIDE

This document is structured into five sections, each addressing a specific theme related to green hydrogen production and its methodological relevance:

- Section 1 provides a detailed market and technology overview, covering hydrogen trends, definitions, pathways, and projections.
- Section 2 addresses lock-in risks by evaluating risks associated with long-term infrastructure or technology choices.
- Section 3 provides a framework for evaluating best available hydrogen production technologies.

- Section 4 supports baseline setting through the determination of ambitious emission benchmarks.
- Section 5 assesses the common practice status of green hydrogen projects.

KEY FACTS AND FIGURES (2024–2025 Data)

- **Negligible Current Share:** Renewable hydrogen represents approximately 0.2% of total global hydrogen supply. Low-emissions hydrogen (green + blue) accounts for less than 1 Mt of approximately 100 Mt total demand — under 1% of production (IEA, 2025a).
- **Project Pipeline — Ambition vs. Reality:** Low-emissions hydrogen could reach 37 Mtpa by 2030 (revised down from 49 Mtpa; IEA, 2025a). Only 9% of the announced project pipeline has reached Final Investment Decision (FID). Operational or FID-approved projects could deliver approximately 4.2 Mtpa by 2030.
- **Persistent Cost Premium:** Green hydrogen costs 1.6–6× more per kg than grey hydrogen. Typical LCOH: $4.00–$8.00/kg in Western markets; $2.50–$5.00/kg in China; vs. $1.00–$2.50/kg for grey hydrogen (IEA, 2025a; Curico, 2025).
- **GHG Emissions Intensity:** Grey hydrogen (SMR) emits ~9–10 kg CO_2/kg H_2 (direct) or 10–12 kg CO_2-eq/kg H_2 (lifecycle). Green hydrogen has near-zero direct emissions; lifecycle: 0.67–1.74 kg CO_2-eq/kg H_2 (Adetona et al., 2025).
- **Electrolyser Capacity:** Global installed capacity reached 2 GW by end-2024 — below the 5 GW projected. China accounts for ~65% of operational capacity. The 500 MW Envision Chifeng project (July 2025) is the world's first half-GW-scale facility.
- **BAT Benchmarks (Direct Emissions, Plant-Gate):** SMR: 8.5 tCO_2/tH_2 | Coal Gasification: 18.0 tCO_2/tH_2 | Naphtha Reforming: 6.3 tCO_2/tH_2. These exclude upstream methane — a deliberate conservativeness choice yielding a baseline ~20–30% below full lifecycle values.

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1.| SECTION 1
GREEN HYDROGEN MARKET: A COMPREHENSIVE ANALYSIS OF ITS CURRENT LANDSCAPE, GROWTH TRAJECTORY, AND COMMERCIALIZATION PATHWAYS

EXECUTIVE SUMMARY

The global energy transition, driven by an imperative to achieve net-zero emissions, positions green hydrogen as a pivotal enabler for decarbonising hard-to-abate sectors such as heavy industry, long-haul transport, shipping, and aviation. While hydrogen itself is a versatile energy carrier, its “green” designation is contingent upon production via water electrolysis powered exclusively by renewable energy sources.

This section provides a detailed analysis of the green hydrogen market to support the methodology for quantifying emission reductions from green hydrogen production projects. Currently, commercial green hydrogen production remains in its nascent stage. The market-penetration and cost figures applied throughout this Supplementary Information are stated once, with sources, at Section 5; they are cross-referenced rather than restated here in order to avoid the divergence between statements of the same dataset that arose in the consultation draft. The summary position is given under Key Facts below.

KEY FACTS (AS OF 2024–2025):

- **Global hydrogen demand** reached approximately 100 Mt in 2024 (IEA, 2025a). Low-emissions hydrogen (green + blue) accounted for less than 1 Mt — under 1% of total production.
- **Installed electrolyser capacity** reached 2 GW by end-2024, with an additional 1+ GW commissioned through mid-2025 (IEA, 2025a). China accounts for ~65% of global operational capacity.
- **Project pipeline:** Low-emissions hydrogen could reach 37 Mtpa by 2030 (revised down from 49 Mtpa; IEA, 2025a). Only 9% of announced projects have reached Final Investment Decision (FID). Operational or FID-approved projects could deliver approximately 4.2 Mtpa by 2030.
- **Cost premium:** Green hydrogen costs 1.6–6× more per kg than grey hydrogen. The LCOH is \$4.00–\$8.00/kg in Western markets and \$2.50–\$5.00/kg in China, versus \$1.00–\$2.50/kg for grey hydrogen (IEA, 2025a; Curico, 2025).
- **GHG emissions intensity:** Grey hydrogen (SMR) emits ~9–10 kg CO_2/kg H_2 (direct) or 10–12 kg CO_2-eq/kg H_2 (lifecycle). Green hydrogen has near-zero direct emissions; lifecycle emissions range from ~0.1 kg CO_2-eq/kg H_2 (hydropower) to ~2.5 kg CO_2-eq/kg H_2 (solar PV) (IEA, 2024a; Gan et al., 2024).

- **Capital spending** on low-emissions hydrogen reached USD 4.3 billion in 2024 (+80% year-on-year), with projections of ~USD 8 billion in 2025 (IEA, 2025a).
- **US policy risk:** The “One Big Beautiful Bill Act” (Public Law 119-21, signed July 4, 2025) curtailed the IRA 45V clean hydrogen production tax credit, shortening the construction deadline from 2033 to January 1, 2028.

1.1| Introduction to Green Hydrogen

1.1.1| Role of hydrogen in the global energy transition

Hydrogen has emerged as a critical and versatile energy carrier, increasingly recognised by governments and industry as a foundational element of a net-zero economy. Its unique properties make it particularly valuable for decarbonising sectors that are inherently challenging to electrify directly — heavy manufacturing (such as steel and chemicals), long-haul freight, maritime shipping, and aviation (Yue et al., 2021). Beyond its direct use as a fuel or feedstock, hydrogen functions as a system integrator: by converting surplus or intermittent renewable electricity into a storable and transportable chemical energy form, green hydrogen can enhance grid stability, provide long-duration energy storage, and improve the integration of variable renewable energy sources (Noussan et al., 2021).

Under IRENA’s 1.5°C Scenario — a normative pathway describing what would be required to limit warming to 1.5°C — green and blue hydrogen production would need to reach 125 Mtpa by 2030 and 523 Mtpa by 2050, potentially abating 12% of global emissions by mid-century (IRENA, 2024a). The IEA’s Net Zero by 2050 roadmap reinforces this, highlighting that a fundamental transformation of the global energy sector, with hydrogen playing a pivotal role, is required (IEA, 2021a).

1.1.2| Importance of Green Hydrogen in Decarbonisation

Green hydrogen — produced through water electrolysis powered by renewable sources — results in near-zero direct greenhouse gas emissions at the production stage. This positions it as the preferred long-term solution for deep decarbonisation. However, the current commercial production of low-emissions hydrogen remains negligible. In 2024, low-emissions hydrogen accounted for less than 1 Mt of approximately 100 Mt total global demand (IEA, 2025a). The enormous gap between current production (~0.2% renewable hydrogen share; Hydrogen Council, 2024) and the 125–523 Mtpa required under ambitious climate scenarios underscores both the urgency of the transition and the formidable challenges that must be overcome.

1.2| Defining Green Hydrogen

1.2.1| Core Definition

Green hydrogen is produced by splitting water molecules (H_2O) into hydrogen (H_2) and oxygen (O_2) through electrolysis using electricity derived exclusively from renewable energy sources. The principal electrolysis technologies are Alkaline Water Electrolysis (AWE, TRL 9), Proton Exchange Membrane (PEM, TRL 9), Solid Oxide Electrolysis (SOEC, TRL 7–8), and the emerging Anion Exchange Membrane (AEM, TRL 5–6) (IEA, 2025b; IRENA, 2020).

1.2.2| Authoritative Definitions

The definition of "green hydrogen" is a critical aspect for policy, investment, and market development, with leading international organizations and national frameworks providing authoritative perspectives. While the core principle of renewable-powered electrolysis is consistent, specific criteria and thresholds can vary, reflecting different regulatory priorities and stages of market development.

Table 1: Definitions of Green Hydrogen

Framework	Core Definition of Green Hydrogen	Key Criteria/Conditions
IRENA	Hydrogen is produced from water electrolysis powered by renewable energy sources (wind, solar, hydro, biogas).	Focus on 100% renewable energy input.
IEA	Hydrogen is produced by the electrolysis of water using renewable electricity. Often uses the broader term "low-emissions hydrogen" to include blue hydrogen.	Emissions intensity < 200–240 gCO_2/kWh electricity input (IEA, 2024a)
European Union (EU) (RFNBO)	"Renewable Fuel of Non-Biological Origin" (RFNBO) produced through electrolysis using renewable electricity.	**GHG Savings:** At least 70% (80% under RED III) compared to fossil fuels. **Additionality:** New renewable electricity generation capacity. **Temporal & Geographic Correlation:** Production when and where renewable electricity is available.
United States (US) (IRA 45V)	Hydrogen with lifecycle GHG intensity <0.45 $kgCO_2e/kgH_2$ (highest credit tier). Calculated using DOE 45VH2-GREET model.	Three pillars: additionality, temporal matching (hourly post-2030), geographic matching. **Note:** P.L. 119-21 (July 2025) shortened the construction deadline to Jan 1, 2028 (Federal Register, 2025; P.L. 119-21, 2025).

1.2.3| Hydrogen Colour Spectrum

The informal “colour spectrum” categorises hydrogen production methods by carbon intensity (IRENA, 2020):

- **Grey Hydrogen:** Produced from fossil fuels (primarily SMR of natural gas or coal gasification) with CO_2 vented to atmosphere. Accounts for ~98% of current production.
- **Blue Hydrogen:** Grey hydrogen with CCUS added to capture >90% of CO_2. Relies on fossil fuels; lifecycle emissions sensitive to methane leakage. Viewed as transitional (Howarth & Jacobson, 2021).
- **Green Hydrogen:** Produced via electrolysis powered by renewable electricity. Near-zero direct emissions. The focus of this methodology.
- **Turquoise Hydrogen:** Methane pyrolysis producing H_2 and solid carbon. No direct CO_2 if renewable-powered (Sánchez-Bastardo et al., 2021). TRL 4–6.
- **Brown/Black Hydrogen:** Coal gasification without CCS. Highly polluting.
- **Pink Hydrogen:** Electrolysis powered by nuclear energy. Low-carbon but not classified as “renewable.”

1.3| Global Green Hydrogen Market (2024-2025)

1.3.1| Current Operational Capacity

Global installed water electrolyser capacity reached 2 GW by end-2024 — significantly below the 5 GW projected in IEA GHR 2024 (IEA, 2025a). An additional 1+ GW was commissioned through mid-2025. China dominates, hosting approximately 65% of global operational capacity. The 500 MW Envision Chifeng project in Inner Mongolia, commissioned in July 2025, represents the world’s first half-GW-scale operational electrolyser facility.

Operational facilities are predominantly concentrated in fewer than ten countries, with significant capacity limited to China, Australia, Germany, Spain, and the United States. Most facilities outside China are small-scale pilots or demonstration projects (<30 ktpa), their primary purpose being to gain operational experience and de-risk technologies rather than to contribute significant commercial volumes.

1.3.2| Market Penetration

Renewable hydrogen production is estimated at approximately 185 kt/yr — representing roughly 0.2% of total global hydrogen supply (Hydrogen Council, 2024). This negligible market share confirms the technology’s nascent status and is a cornerstone of the Common Practice Analysis (Section 6 of this SI).

1.3.3| Geographical Distribution of Green Hydrogen Production[1]

Conventional hydrogen production is concentrated in regions with abundant fossil fuels: China (~38 Mt, primarily coal gasification), the US (~10 Mt, primarily SMR), India (~6.5 Mt), Russia, and the Middle East. The geography of green hydrogen is fundamentally different, driven by renewable energy potential rather than fossil fuel access. Key emerging hubs include Australia (solar/wind for export), the Middle East and North Africa (exceptional solar resources, exemplified by the NEOM project in Saudi Arabia), Latin America (Chile's Atacama solar, Brazil's wind/hydro), and Europe (offshore wind, industrial decarbonisation). China's dominance in both renewable energy deployment and electrolyser manufacturing (nearly 60% of global capacity; IEA, 2025a) gives it a structural advantage.

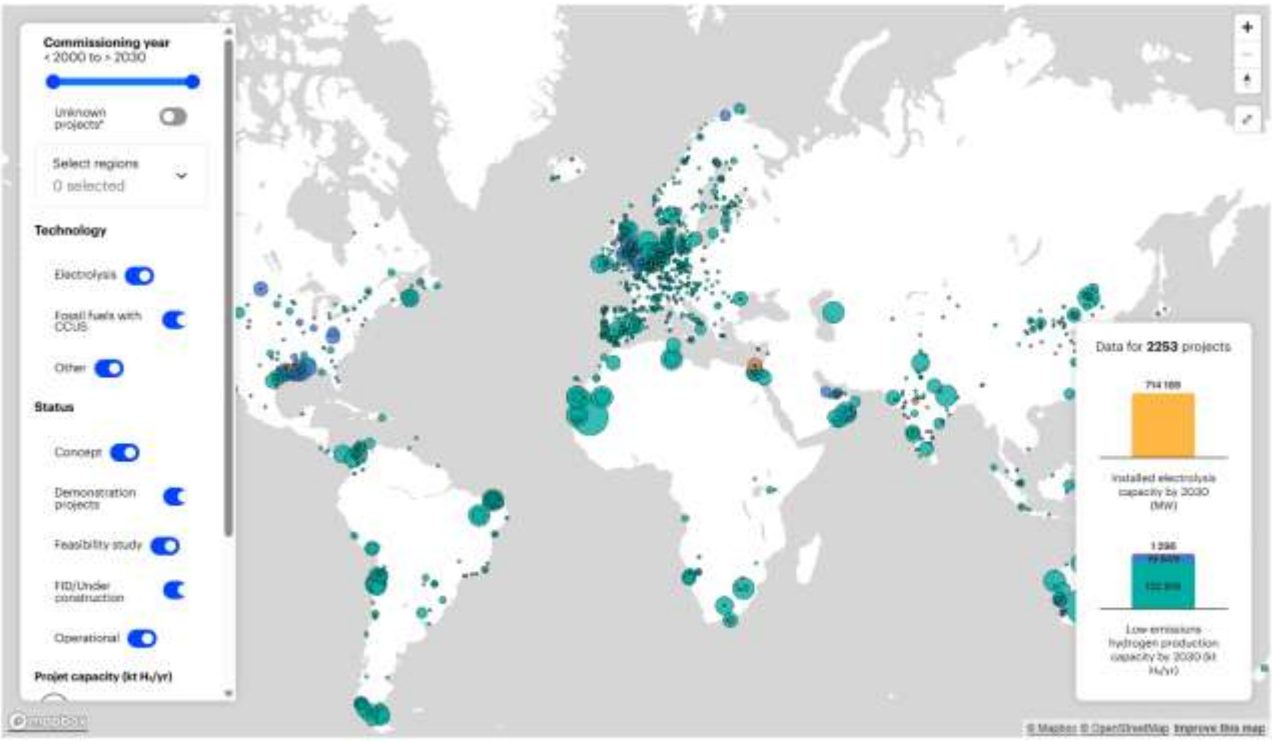

Figure 1 Hydrogen Production Projects Interactive Map (https://www.iea.org/data-and-statistics/data-tools/hydrogen-production-projects-interactive-map, accessed on 21 June 2025))

1.4| Comparative Analysis of Hydrogen Production Pathways

The transition to a low-carbon hydrogen economy requires a thorough understanding of the various production pathways, particularly the distinctions between green hydrogen and its conventional or transitional counterparts. This comparative analysis delves into the scale, technological maturity, operational characteristics, and costs associated with each method.

[1] Hydrogen production – Global Hydrogen Review 2024 – Analysis - IEA, accessed June 19, 2025

1.4.1| Green Hydrogen vs. Grey Hydrogen

The differences between green and conventional (grey) hydrogen production facilities reflect their distinct energy sources, environmental impacts, and stages of industrial development.

1.4.1.1 Production Scale and Capacity

A defining characteristic of the conventional hydrogen industry is its operation at very large scales, driven by the pursuit of economies of scale in steam methane reforming (SMR) or autothermal reforming (ATR) units. Capacity is conventionally quoted in normal cubic metres per hour. A world-scale single train at 100,000 Nm^3/h produces approximately 0.079 Mtpa of hydrogen at continuous operation, or about 0.071 Mtpa at a typical 90% availability (100,000 $Nm^3/h \times 8{,}760\ h \times 0.08988\ kg/Nm^3$). The largest single trains, at roughly 200,000 Nm^3/h, reach approximately 0.14 Mtpa on the same basis. Large refining and chemical complexes aggregate several such trains at one site.
In contrast, operational green hydrogen plants are significantly smaller. Most are pilot or demonstration facilities, with capacities typically below 30 ktpa (less than 0.03 Mtpa). This limited scale is primarily due to the current capacity and cost of electrolyser units. However, the ambition for future green hydrogen projects is rapidly scaling up to match and potentially exceed conventional plant sizes. The largest announced green hydrogen projects target hydrogen output of the order of 0.2 to 0.4 Mtpa, comparable to three to five world-scale conventional trains. Announced capacities require care: where a project converts its hydrogen to ammonia for export, the headline tonnage is commonly the ammonia output, which overstates hydrogen output by a factor of approximately 5.6, since ammonia contains 0.1776 tonnes of hydrogen per tonne. A stated electrolyser rating provides an independent check, as set out at Table 4. Achieving such scales requires deploying electrolyser capacity in gigawatts (GW), demonstrating that while current green hydrogen operations are small, the industry is aiming to match conventional scale in its next generation of projects, recognizing that cost-competitiveness likely requires leveraging economies of scale in both massive renewable energy deployment and large-scale electrolysis and downstream processes.

1.4.1.2 Technological Maturity

Conventional hydrogen production relies on technologies that are highly mature and have been optimized over a century. Steam Methane Reforming is a well-understood, reliable technology with established supply chains and extensive operational expertise.
Green hydrogen production, while leveraging mature downstream synthesis processes where applicable, replaces the fossil-fuel-based hydrogen production front-end with water electrolysis powered by renewables. Electrolysis technologies themselves (Alkaline Water Electrolysis - AWE, Polymer Electrolyte Membrane - PEM, Solid Oxide Electrolysis - SOE) are at varying stages of maturity.
AWE is more established; PEM offers greater flexibility but is still developing; and SOE promises higher efficiency but is less mature.

This difference in technological maturity creates a distinct risk-reward profile, with conventional hydrogen benefiting from proven reliability and predictable costs, while green hydrogen offers a zero-emission pathway but relies on rapidly evolving technology, introducing risks related to cost projections, scaling, and operational integration, alongside the opportunity for significant cost reductions through continued innovation.

1.4.1.3 Operational Characteristics (Energy Consumption, CO2 Emissions, Feedstock)

The operational characteristics of green and conventional hydrogen plants differ significantly, primarily due to their disparate energy sources and process configurations.

- **Energy Consumption:** Both processes are energy-intensive. Conventional SMR-based production consumes significant amounts of natural gas, both as feedstock and fuel, contributing to the sector's approximately 1.8-2% share of global energy use. Green hydrogen production via electrolysis is also highly energy-intensive, but the input is primarily electricity.
- **CO_2 Emissions:** Conventional production results in high CO_2 emissions, typically 9-10 kg of CO_2 per kg of hydrogen. In contrast, green hydrogen production, using renewable electricity, has near-zero direct CO_2 emissions.[2]
- **Feedstock:** Conventional hydrogen production relies on fossil fuels (natural gas, coal, oil) as both feedstock and energy source. Green hydrogen production relies primarily on water (for electrolysis) and, for certain derivatives, air (as the source of nitrogen), with renewable electricity as the primary energy input. Access to sufficient freshwater resources can be a constraint for large-scale green hydrogen production, potentially necessitating desalination (which adds energy cost) in arid regions.
- **Operational Flexibility:** Conventional hydrogen production plants are designed for and operate most efficiently under stable, continuous (24/7) conditions, with limited flexibility to rapidly ramp production up or down. Green hydrogen plants powered by intermittent renewable sources like solar and wind face the challenge of integrating a variable power supply with the steady-state requirements of downstream processes. This requires strategies such as incorporating energy storage (e.g., batteries), hydrogen storage (to buffer the H_2 supply), oversizing renewable generation and electrolysis capacity, or developing more flexible downstream processes.

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[2] Integration of Government Policies on the Global Level for Green Hydrogen Production, Green Hydrogen Economy for Environmental Sustainability. **Volume** 1: Fundamentals and Feedstocks Chapter 1pp 1-28, ACS Symposium Series Vol. 1473, accessed June 19, 2025

1.4.1.4 Current Production Costs (Levelized Cost of Hydrogen - LCOH)

Currently, green hydrogen production costs are significantly higher than conventional grey hydrogen costs. The LCOH for green hydrogen varies significantly by region. In Western markets (US, EU, Australia), LCOH typically ranges from $4.00–$8.00/kg in 2024/2025. In China, where renewable electricity, electrolyser costs, and the cost of capital are substantially lower, LCOH can be 40–45% lower, potentially reaching $2.50–$4.00/kg (IEA, 2025). Grey hydrogen LCOH remains at approximately $1.00–$2.50/kg depending on natural gas prices. The cost premium for green hydrogen therefore ranges from approximately 60% to over 300% depending on the region, vastly exceeding the 20% threshold used in CDM Tool 24 to classify a technology as 'different'.
The primary drivers of green hydrogen cost are the price of renewable electricity, which can account for 50-70% of total production costs, and the capital expenditure (CAPEX) for electrolysers. Green hydrogen is projected to become cost-competitive with grey hydrogen only under scenarios with very low renewable electricity prices (e.g., below $20/MWh) or significant carbon pricing applied to grey hydrogen emissions (e.g., >$150/tonne CO_2). Policy incentives, such as the production tax credits in the US Inflation Reduction Act (IRA), can substantially improve the economics of green hydrogen, potentially making it competitive with or even cheaper than unabated grey hydrogen. However, without financial subsidies, the IEA predicts that the cost reduction to $2-3/kg H_2 by 2030 is unlikely to materialize.

Table 2: Comparative Summary of Hydrogen Production Pathways

Feature	Grey Hydrogen	Blue Hydrogen	Green Hydrogen
Primary Feedstock	Natural Gas, Coal	Natural Gas	Water
Primary Energy Source	Fossil Fuels	Fossil Fuels	Renewable Electricity
Key Technology	SMR, ATR, Coal Gasification	SMR/ATR + CCUS	Water Electrolysis (AWE, PEM, SOEC)
Direct CO_2 Emissions	High (9–10 $kgCO_2/kgH_2$ for SMR; 18–20 for coal)	Reduced (depends on capture rate; real-world: 35–80% of total facility emissions captured)	Near-zero
LCA Emissions ($kgCO_2$-eq/kgH_2)	10–12 (NG); 22–26 (coal)	2.8–9.3 (highly variable)	0.1–2.5 (depending on RE source)
Current Plant Scale	Large (0.7–3.5 Mtpa)	Large (leveraging SMR)	Small (<0.03 Mtpa); targeting 1–3 Mtpa
Current LCOH ($/kg)	$1.00–$2.50	$2.00–$4.00	$2.50–$8.00 (region-dependent)

Sources: IEA (2024a); IEA (2025a); Patel et al. (2024); Capodaglio et al. (2024); Curico (2025); Howarth & Jacobson (2021). For detailed BAT analysis, see Section 3 of this SI.

1.4.2| Green Hydrogen vs. Blue Hydrogen

Blue hydrogen represents another significant pathway aimed at reducing the carbon footprint of hydrogen production, often viewed as a transitional technology alongside green hydrogen.

1.4.2.1 Production Process and Emissions Profile

Blue hydrogen production typically begins with the conventional SMR process using natural gas to produce hydrogen. However, it incorporates Carbon Capture, Utilization, and Storage (CCUS) technology to capture the CO_2 generated during the process, preventing over 90% of it from being released into the atmosphere. The captured CO_2 is then transported and stored permanently underground in geological formations or potentially utilized in other industrial processes.

While it significantly reduces emissions compared to grey hydrogen, it still relies on fossil fuel feedstocks and the associated upstream emissions (e.g., methane leakage during natural gas extraction and transport) are not fully mitigated.

In contrast, green hydrogen is produced using renewable electricity for water electrolysis, resulting in virtually zero direct CO_2 emissions at the production stage. This fundamental difference in feedstock and energy source gives green hydrogen a superior environmental profile in terms of direct production emissions.

1.4.2.2 Cost Competitiveness and Transitional Role

Economic analyses generally suggest that blue hydrogen may be less expensive than green hydrogen in the near term, particularly in regions with established natural gas infrastructure and suitable geology for CO_2 storage, and especially when supported by policy incentives like tax credits. The LCOH for blue hydrogen typically ranges from $2.00–$3.50/kg, positioning it as an intermediate cost option between grey and green hydrogen. IRENA notes that green hydrogen is currently two to three times more expensive than blue hydrogen.

Blue hydrogen is often viewed as a transitional technology because it leverages existing SMR plant infrastructure, potentially enabling faster deployment and larger scale-up compared to building entirely new greenfield green hydrogen facilities. This cost advantage and ability to retrofit existing assets make blue hydrogen both a competitor to green hydrogen and a potentially significant contributor to decarbonizing the hydrogen-consuming sectors during the transition period. Investment decisions in the coming years may favor blue hydrogen in certain contexts, potentially influencing the pace and specific pathway of the broader shift towards low-emission hydrogen production. However, its reliance on fossil fuels and the long-term viability of CCUS remain subjects of ongoing debate, while green hydrogen is seen as the ultimate long-term solution for deep decarbonization.

1.4.3| Electrolyser Technologies

The choice of electrolysis technology is a critical factor in green hydrogen production, influencing efficiency, capital costs, and operational flexibility, particularly in integrating with intermittent renewable energy sources. The three main technologies are Alkaline Water

Electrolysis (AWE), Polymer Electrolyte Membrane (PEM) electrolysis, and Solid Oxide Electrolysis (SOE).

1.4.3.1 Technological Maturity and Efficiency

- **Alkaline Water Electrolysis (AWE):** AWE is the most mature and established electrolysis technology, with a long history of commercial operation spanning over 100 years. Its system efficiency in 2020 ranged from 50-78 kWh/kg H_2, with a target of less than 45 kWh/kg H_2 by 2050. While robust, conventional AWE electrolyser are designed for fixed process conditions, making their integration with fluctuating renewable energy sources challenging due to a limited part-load range and increased gas impurity at low power availability.
- **Polymer Electrolyte Membrane (PEM) Electrolysis:** PEM electrolysis is a rapidly developing technology, considered to be in its early to moderate stage of maturity, but with significant potential for growth. It offers high efficiency, with system efficiency ranging from 50-83 kWh/kg H_2 in 2020, targeting less than 45 kWh/kg H_2 by 2050. PEM electrolyser are particularly noted for their high dynamics, rapid response times, and ability to efficiently harness volatile energy generated from intermittent renewable sources like wind and solar.
- **Solid Oxide Electrolysis (SOE):** SOE is generally considered the least mature of the three main technologies but offers the highest potential for efficiency gains. Its system efficiency in 2020 ranged from 40-50 kWh/kg H_2, with an ambitious target of less than 40 kWh/kg H_2 by 2050. SOE operates at high temperatures (700-850°C), which allows it to utilize waste heat from industrial processes, potentially leading to higher overall system efficiencies. However, these high operating temperatures also present material challenges and slower cold start times.

1.4.3.2 Capital Costs and Operational Flexibility

- **Alkaline Water Electrolysis (AWE):** AWE generally has lower capital costs compared to PEM and SOE. The estimated capital cost range for an entire AWE system (>10 MW) in 2020 was USD 500-1,000/kWel, with a target of less than USD 200/kWel by 2050. While its CAPEX is relatively lower, AWE's operational flexibility is limited by its slower response to load changes, which can be a drawback when integrating with highly variable renewable energy sources.
- **Polymer Electrolyte Membrane (PEM) Electrolysis:** PEM electrolysers typically have higher capital costs than AWE, primarily due to the use of precious metal catalysts (e.g., platinum, iridium). The estimated capital cost range for an entire PEM system (>10 MW) in 2020 was USD 700-1,400/kWel, with a target of less than USD 200/kWel by 2050. Despite the higher initial investment, PEM's high operational flexibility, rapid response to load changes, and ability to handle

intermittent power make it well-suited for direct coupling with variable renewable energy sources, offsetting some of its cost premium. [3]

- **Solid Oxide Electrolysis (SOE):** SOE currently has the highest capital costs among the three, with stack costs (for >1 MW) exceeding USD 2,000/kWel in 2020, targeting less than USD 200/kWel by 2050. While less mature and more expensive upfront, SOE's potential for very high efficiency, especially when integrated with waste heat sources, could lead to lower operational costs in specific industrial applications. Its operational flexibility is somewhat constrained by its high operating temperatures and slower start-up times compared to PEM.

In essence, the choice among these technologies involves a trade-off between maturity, capital cost, and the ability to integrate seamlessly with the dynamic nature of renewable energy supply. Continued research and development are focused on improving the efficiency, durability, and cost-effectiveness of all electrolyser types to unlock the full potential of green hydrogen production.

Table 3: Key Performance Indicators for Electrolyser Technologies (2024 and Targets)

Feature	AWE	PEM	AEM	SOEC
TRL	9 (Commercial)	9 (Commercial)	5–6 (Demo)	7–8 (Pre-commercial)
Efficiency (system, 2024)	48–55 kWh/kgH_2	50–60 kWh/kgH_2	55–70 kWh/kgH_2	37–45 kWh/kgH_2
2050 Target	<45 kWh/kgH_2	<45 kWh/kgH_2	<45 kWh/kgH_2	<40 kWh/kgH_2
Stack Lifetime (2024)	80,000–100,000 hrs	50,000–80,000 hrs	>5,000 hrs	40,000–60,000 hrs
CAPEX — China (2024)	$500–1,200/kWel	$600–1,300/kWel	N/A	N/A
CAPEX — Western (2024)	$1,200–2,450/kWel	$1,400–2,600/kWel	N/A	>$2,000/kWel
2050 Target	<$200/kWel	<$200/kWel	<$200/kWel	<$300/kWel
Operational Flexibility	Moderate (slower ramp)	High (rapid response)	Emerging	Lower (high-temp start-up)

Sources: IEA (2025a); IEA (2025b); IRENA (2021); US DOE Program Record #24005 (2024); European Hydrogen Observatory (2026).

Note: Electrolyser costs have bifurcated sharply: Chinese systems are approximately 40–50% of Western costs. Non-Chinese manufacturers are experiencing significant financial distress, with

[3] Understanding electrolyser performance: A comprehensive guide to metrics and best practices, siemens-energy.com

several bankruptcies and acquisitions in 2024–2025 (IEA, 2025a). The long-term target of <$200/kWel by 2050 remains, but progress has been slower than anticipated.

1.5 | Growth Potential and Future Outlook

While current commercial green hydrogen production is minimal, the future outlook is characterized by significant ambition, driven by global decarbonization efforts and emerging new markets for hydrogen and its derivatives.

1.5.1 | Project Pipeline: Ambition vs. Reality

The IEA Global Hydrogen Review 2025 provides the most authoritative assessment of the pipeline (IEA, 2025a):

- Low-emissions hydrogen production could reach **37 Mtpa by 2030** — a significant downward revision from 49 Mtpa (GHR 2024) and the aspirational 65 Mtpa originally envisaged.
- **9% of announced projects** have reached FID (up from 4% in GHR 2024). Cancellations and delays drove the overall pipeline reduction.
- **Operational or FID-approved projects** could deliver approximately 4.2 Mtpa by 2030.
- **Capital spending** reached USD 4.3 billion in 2024 (+80% year-on-year), rising to ~USD 8 billion in 2025. Electrolysis accounts for 80% of spending.

Under normative scenarios, the scale-up required is enormous: IRENA's 1.5°C scenario requires 125 Mtpa by 2030 and 523 Mtpa by 2050, necessitating 428 GW of electrolysers by 2030 and 5,722 GW (5 TW+) by 2050 (IRENA, 2024a). The gap between what is needed (125 Mtpa) and what is likely (4.2–16 Mtpa) represents the "implementation chasm" that carbon finance mechanisms are designed to help bridge.

Table 2: Selected Major Announced Low-Emission Hydrogen Projects

Project	Location	Capacity (Mtpa H_2)	Technology	Status (mid-2026)	Target Start
NEOM Green H_2	Saudi Arabia	0.22	Green / 2.2 GW	Under Construction (~80% complete)	2027
Envision Chifeng	China (Inner Mongolia)	~0.06	Green / 500 MW AWE	**Operational** (July 2025)	2025 ✓
CF Industries / Mitsui / JERA	USA (Louisiana)	1.1	Blue (SMR + CCS)	FID (Apr 2025)	2029
TA'ZIZ Blue H_2	UAE (Abu Dhabi)	1.1	Blue (SMR + CCS)	Under Construction	2027
ACME Phase 1	Oman (Duqm)	0.1 (Phase 1)	Green / 3.5 GW (total)	Construction (Phase 1)	Q1 2027

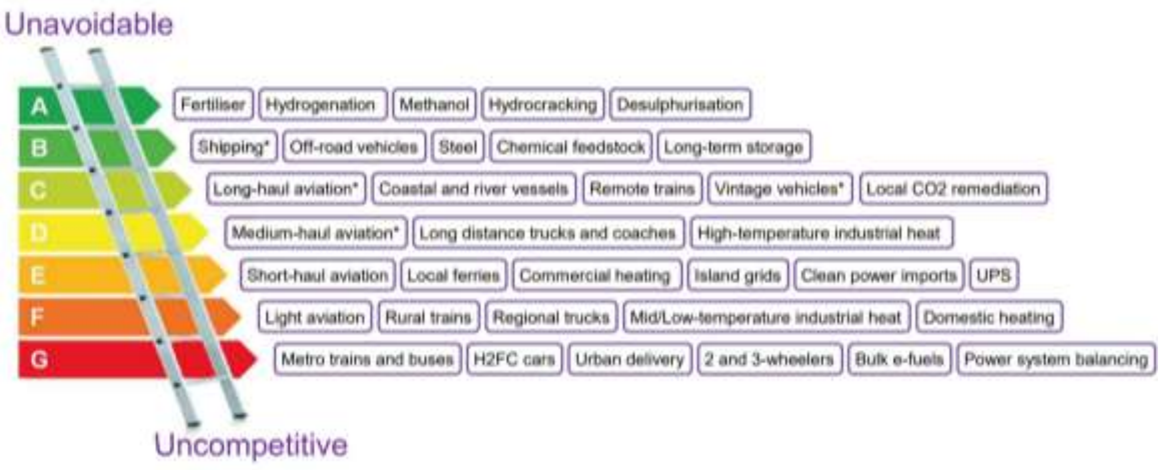
Murchison	Australia (WA)	0.3	Green / ~3 GW	Pre-FID / Developing	~2031

Note: IEA (2025a); project developer announcements. Status subject to change. Capacities are stated as hydrogen. Where a project's headline announcement is denominated in ammonia, the hydrogen figure is derived at 0.1776 tH_2/tNH_3. Green-pathway entries are cross-checked against the stated electrolyser rating: at a specific energy consumption of 50 kWh/kgH_2 (Section 3) and a capacity factor of 50–85%, 1 GW of electrolysis yields approximately 0.09–0.15 Mtpa of hydrogen.

1.6| Emerging Applications

The growth potential of green hydrogen is not solely predicated on decarbonizing existing hydrogen uses but also on unlocking vast new markets and applications. Priority applications, classified using the Liebreich Associates Clean Hydrogen Ladder (v4.1; Liebreich, 2024), include:

- **Tier A–C (Unavoidable / High-priority):** Replacing grey hydrogen in ammonia/fertiliser production, oil refining, and petrochemicals; green steel via Direct Reduced Iron (DRI); sustainable aviation fuels (e-SAF); maritime shipping fuel (e-ammonia).
- **Tier D–F (Competitive / Niche):** Non-road mobile machinery, long-duration energy storage, remote/off-grid power, short-term grid balancing.
- **Tier G (Uncompetitive):** Domestic heating, power generation using non-stored hydrogen — where electrification is cheaper, safer, or more efficient.



* Via ammonia or e-fuel rather than H2 gas or liquid — Source: Liebreich Associates (concept credit: Adrian Hiel/Energy Cities)

These new market opportunities, coupled with the increasing global emphasis on decarbonization, are expected to drive exponential growth in green hydrogen demand. The development of these applications is crucial for achieving economies of scale, reducing production costs, and ultimately making green hydrogen a competitive and indispensable element of the future energy system. Furthermore, to prevent carbon lock-in and ensure environmental integrity, the methodology should restricts crediting to high-priority applications (Rows A and B, such as chemical feedstock and maritime shipping) while explicitly excluding 'Uncompetitive' tiers (Rows E, F, and G) where direct electrification is fundamentally more efficient.

1.7| Drivers and Hurdles for Commercialisation

The trajectory of green hydrogen from a niche product to a major energy commodity is shaped by a complex interplay of powerful drivers and significant hurdles. Understanding these factors is critical for stakeholders navigating this emerging market.

1.7.1| Key Drivers for Adoption

Several compelling factors are propelling the push towards green and low-emission hydrogen:

- **Decarbonisation mandates:** Paris Agreement targets and national NDCs necessitate zero-carbon solutions for hard-to-abate sectors.
- **Policy support:** EU RED III (42% RFNBO for industrial H_2 by 2030; Directive 2023/2413/EU); US IRA 45V (up to $3.00/kg, now time-limited to Jan 2028; P.L. 119-21); European Hydrogen Bank auctions (€720M first round; €1.2B second round); Australia Hydrogen Headstart.
- **Falling renewable energy costs:** Renewable LCOE has declined ~90% since 2010, directly improving green hydrogen economics.
- **Energy security:** Domestic renewable hydrogen reduces dependence on volatile fossil fuel imports.

1.7.2| Major Hurdles

- **Cost competitiveness:** Green hydrogen LCOH is 1.6–6× that of grey hydrogen. A carbon price of €100–€300/tCO_2 would be required for parity in most markets (Agora Energiewende & Guide house, 2021).
- **Intermittency management:** Coupling electrolysers with variable renewables requires energy storage, oversizing, or grid backup — adding cost and complexity.
- **Infrastructure deficit:** Dedicated hydrogen pipelines take 7–12 years to plan and build. Construction of the first 30 km of the Dutch hydrogen backbone began in October 2024 as part of a planned 1,200 km network (IEA, 2025a).
- **Water availability:** Total water demand is 18–30 L/kg H_2 including cooling (Simoes et al., 2024). This poses constraints in water-stressed regions with high solar potential, necessitating desalination.
- **Offtake gap:** Only 12% of planned 2030 green hydrogen production has a secured buyer (IRENA, 2024b). This prevents financing, which prevents the scaling needed to reduce costs.
- **US policy risk:** The curtailment of the IRA 45V credit by P.L. 119-21 introduces significant uncertainty for US-based projects and weakens the global policy signal.

- **Manufacturer distress:** Non-Chinese electrolyser manufacturers are experiencing “sharp reductions in revenue and increased financial losses” (IEA, 2025a), with several bankruptcies and acquisitions in 2024–2025.

1.8 | Conclusion

The global hydrogen industry stands at a pivotal juncture. Conventional grey hydrogen overwhelmingly dominates current supply (~98%), but its carbon footprint is increasingly misaligned with climate objectives. Green hydrogen offers a near-zero-emission pathway but remains commercially negligible (<0.2% of global supply), economically uncompetitive without subsidies (LCOH 1.6–6× grey), and geographically concentrated (65% of operational capacity in China alone).

The downward revision of the 2030 pipeline from 49 to 37 Mtpa, the persistent offtake gap (88% of planned production without a buyer), and the curtailment of the most generous global subsidy (US 45V) collectively confirm that green hydrogen cannot achieve commercial viability through market forces alone. Carbon finance — through mechanisms such as this methodology — provides a critical, complementary revenue stream that can help bridge the gap between policy ambition and investable reality.

For detailed analysis of green hydrogen’s lock-in risk, BAT determination, benchmark emission factors, and common practice status, see Sections 2, 3, 4, and 5 of this SI, respectively.

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2.| SECTION 2 LOCK-IN RISK ANALYSIS FOR GREEN AND LOW-CARBON HYDROGEN PRODUCTION ACTIVITIES

2.1| Introduction

Technology lock-in, within the context of climate change mitigation, describes a situation where investments in particular technologies — especially those involving long-lived infrastructure — create path dependencies that perpetuate their use, thereby hindering the transition towards lower-carbon or zero-carbon alternatives (Unruh, 2000). This phenomenon is particularly pertinent to energy systems, where infrastructure such as production plants, pipelines, and industrial facilities often has operational lifetimes spanning 20–50 years. Long-term commitments to specific technologies can inadvertently obstruct the achievement of climate objectives, including the Paris Agreement's goal of limiting global warming to well below 2°C, preferably 1.5°C (Seto et al., 2016). The potential for carbon lock-in underscores the critical need to evaluate new energy investments not only for their immediate emissions profile but also for their compatibility with deep decarbonisation pathways extending to mid-century and beyond.

Hydrogen is increasingly viewed as a key enabler for decarbonisation across multiple sectors, driving a significant global expansion of planned production capacity. However, the concept of lock-in is not confined to the dichotomy between fossil fuels and renewables; it is equally relevant within the portfolio of low-carbon technologies themselves. Transitional solutions such as "blue" hydrogen (produced from fossil fuels with carbon capture), while offering lower emissions than conventional "grey" hydrogen, still involve long-lived fossil-based infrastructure and residual emissions. Policies that broadly support "low-carbon" hydrogen without strong differentiation or phase-out mechanisms for fossil-based pathways could perpetuate reliance on solutions that are not fully compatible with long-term net-zero goals — a "soft lock-in" that undermines climate ambition.

2.2| Objective and Scope

This section conducts a formal lock-in risk analysis for green hydrogen production, with blue and turquoise hydrogen included for comparative risk identification. The analysis is framed against the specific lock-in criteria derived from the GS4GG standard *Requirements for Additionality Demonstration* (Section 6.2), which mandates that methodologies ensure activities avoid locking in levels of emissions, technologies, or carbon-intensive practices incompatible with the long-term goals of the Paris Agreement. This is consistent with the UNFCCC Article 6.4 Supervisory Body standard A6.4-SB009-A01 (UNFCCC, 2024a), from which the GS4GG criteria are derived.

While the GS4GG Green Hydrogen methodology strictly excludes fossil-derived hydrogen for crediting (grey, brown, blue pathways), this section analyses these pathways for comparative risk identification. The analysis covers the primary low-carbon hydrogen production pathways — green, blue, and turquoise — across key geographical regions.

2.3| Assessment Framework

2.3.1| GS4GG Lock-in Risk Criteria

This section outlines the methodology followed for low-carbon Hydrogen production activities to assess technology lock-in – in particular assessed against the specific criteria outlined in the GS4GG's standard Requirements for additionality demonstration, Section 6.2, "Lock-in risk analysis". This standard requires that GS4GG methodologies ensure activities avoid lock-in.

The assessment considers the following key factors derived from the standard:

a. **Compatibility with the long-term goals of the Paris Agreement:** Ensuring the project aligns with limiting global warming well below 2°C, preferably to 1.5°C.

b. **Consistency with the host country's Long-Term Low Emission Development Strategy (LT-LEDS), where submitted:** Where submitted, projects must align with national long-term decarbonization plans.

c. **Utilization of technology with the lowest feasible greenhouse gas intensity for long-lifetime investments, considering regional context:** This criterion considers the regional context and the evolving landscape of clean technologies.

d. **Avoidance of inefficient use of resources critical for climate change mitigation or other policy objectives:** Such as water or land.

e. **Consideration of socio-economic contexts, existing infrastructure, and path dependencies:** Recognizing local conditions and historical development that might influence technology choices.

f. **Technical or operational lifetime of the technologies or practices:** Longer lifetimes imply a higher risk of lock-in if the technology is not fully compatible with future decarbonization needs.

g. **Emissions intensity of these technologies and practices:** Both direct operational and lifecycle emissions are considered.

h. **Scale of the activity:** Larger projects inherently amplify potential lock-in consequences

i. **Availability and feasibility of alternative options given national circumstances:** An assessment of whether viable, lower-emission, or more resource-efficient alternatives exist within the national context

j. **Potential exemption from detailed analysis for technologies with lifetimes ≤ 10 years:** While this criterion exists, it is unlikely to apply to entire hydrogen production facilities given the multi-decade lifespan of core components

2.3.2| Stepwise Assessment Process

The lock-in risk assessment follows a structured process:

Step 1 — Project Component Analysis: Each infrastructure component is evaluated for its potential to create fossil fuel dependency, extend high-emission infrastructure lifespans, or preclude future decarbonisation.

Step 2 — Comparison to Baseline (BAU): The activity scenario is compared against a Business-as-Usual baseline involving fossil-based hydrogen production with typical lifetimes of 30–40 years.

Step 3 — Qualitative Checklist: The project should confirm it meets all criteria for lock-in avoidance: no fossil fuel combustion in any process; renewable energy infrastructure is modular and upgradable; no long-term contracts for fossil-based inputs; and compliance with national net-zero pathways.

2.4| Technology Lifetimes and Compatibility with Long-Term Goals

The operational lifetime of the infrastructure associated with hydrogen production is a primary determinant of lock-in risk. Long-lived assets installed today commit capital and potentially emissions for decades, influencing future investment decisions and potentially hindering alignment with evolving climate targets

The operational lifetime of the infrastructure associated with hydrogen production is a primary determinant of lock-in risk. Long-lived assets installed today commit capital and potentially emissions for decades, influencing future investment decisions and potentially hindering alignment with evolving climate targets. Based on available information, typical operational lifetimes for key components are summarised in the table below.

Table 5: Estimated Operational Lifetimes of Key Low-Carbon Hydrogen Production Components

Component	Type	Estimated Lifetime	Key Factors	Source
Electrolyser System	AWE	20–30 years (with stack replacements)	Maintenance, operating conditions	IRENA (2021); EPRI (2022)
	PEM	20–30 years (with stack replacements)	Stack degradation, operating cycles	Gerhardt-Mörsdorf et al. (2024)
	SOEC	15–25 years (with stack replacements)	High-temp degradation, material stability	ScienceDirect (2025a)
Electrolyser Stack	AWE	80,000–100,000 hrs (~9–11 yrs)	Electrode/membrane stability	EPRI (2022); IEA (2025a)

	PEM	50,000–80,000 hrs (~5.7–9 yrs)	Membrane/catalyst degradation; 0.25–2.5%/yr degradation rate	Gerhardt-Mörsdorf et al. (2024); ScienceDirect (2025b)
	SOEC	40,000–60,000 hrs (~4.5–7 yrs)	High-temp degradation, material stability	ScienceDirect (2025a)
	AEM	>5,000 hrs (emerging)	Membrane stability	IEA (2025b)
Hydrogen Storage Tanks	Various	Up to 30 years	Material integrity, operating conditions	OIES (2024)
Hydrogen Pipelines	New-build	~50 years	Material integrity, corrosion	OIES (2024)
	Repurposed NG	~30 years	Hydrogen embrittlement risk requires ongoing integrity management	OIES (2024)
CCUS Equipment	Various	>20 years	Integration with host plant	IEAGHG (2024)
SMR/ATR Plant	Conventional	30–40 years	Well-established; creates high lock-in risk	IEA (2023a)

Note: Lifetimes are estimates and can vary based on specific design, operation, and maintenance practices.

2.4.1| Compatibility Assessment with Paris Agreement Goals:

a. **Green Hydrogen:** The physical infrastructure involves components with lifetimes extending beyond 2050. However, the core hydrogen production unit — the electrolyser stack — has a relatively short lifetime (5–11 years), enabling periodic technology upgrades without replacing the entire facility. This modularity is a critical lock-in mitigation feature. The system creates no dependency on fossil fuel feedstocks and is operationally compatible with net-zero pathways if powered exclusively by renewable energy.

b. **Blue Hydrogen:** SMR/ATR plants coupled with CCS represent significant long-term investments in fossil-fuel-based infrastructure, with typical lifetimes exceeding 20 years. This presents a direct conflict with the trajectory required for a 1.5°C world. Investing in new blue hydrogen facilities today risks creating assets that are misaligned with climate goals for a substantial portion of their operational life. A landmark peer-reviewed analysis demonstrated that when accounting for realistic methane leakage rates (3.5%) and using GWP_{20}, blue hydrogen emissions are only 9–12% lower than grey hydrogen (Howarth & Jacobson, 2021). Furthermore, economic modelling confirms that blue hydrogen assets deployed within the next three decades face “a substantial risk” of becoming stranded (Fazeli et al., 2025). No new blue hydrogen projects commenced production in 2024 (IEA, 2025a). Real-world carbon capture rates at operational facilities have consistently fallen short of the 90%+ targets used in modelling, with reported rates of 35–80% of total facility emissions (IEEFA, 2023).

c. **Turquoise Hydrogen:** Similar to blue hydrogen, this pathway relies on natural gas feedstock and involves long-lived plant infrastructure. Its compatibility depends on using zero-carbon energy for the pyrolysis process and ensuring the long-term, verifiable sequestration or sustainable use of the solid carbon produced. The reliance on fossil gas feedstock still presents a lock-in risk related to continued fossil fuel extraction and infrastructure.

2.5| Greenhouse Gas Intensity Assessment

2.5.1| GHGs Emissions

The GHG intensity of the produced hydrogen is a crucial factor in assessing lock-in risk, particularly concerning the A6.4 criterion requiring the use of technologies with the "lowest greenhouse gas intensity" feasible in the relevant region for long-lifetime investments. Comparing the lifecycle GHG intensity across pathways requires careful consideration of system boundaries, GWP metrics (e.g., AR5 vs. AR6), and the inclusion of upstream and embodied emissions.

a. **Grey Hydrogen (SMR without CCS):** Grey Hydrogen (SMR without CCS): Serves as the baseline for comparison. Lifecycle assessments typically report intensities around 9.2 to 11.1 kg CO2eq/kg H2.

b. **Blue Hydrogen (SMR/ATR + CCS):** GHG intensity is highly variable. Key factors include the CO2 capture rate (typically 90-98% targeted for the process emissions) and, critically, upstream methane emissions from the natural gas supply chain. A 90% carbon capture rate does not equate to a 90% emissions reduction, as additional energy is required for capture and supply chain emissions persist. Upstream methane leakage can significantly impact overall GHG intensity for hydrogen, with estimates around 0.34 g CH4 per MJ hydrogen. This methane leakage is not mitigated by CCUS technology applied to blue hydrogen. The significant impact of upstream methane leakage cannot be overstated. Analysis suggests that methane leaks can contribute substantially to the overall emissions, potentially dwarfing direct process emissions remaining after high CCS capture rates. This makes robust measurement, reporting, verification (MRV), and mitigation of upstream methane absolutely critical for blue hydrogen to deliver credible climate benefits and avoid locking in significant GHG emissions. Methane's high Global Warming Potential (GWP), particularly over a 20-year horizon (e.g., 85 gCO2e vs. 30 gCO2e for 100-year GWP), means that unmitigated upstream methane can diminish blue hydrogen's GHG reduction benefits, potentially making it worse than fossil fuels in the short term.

c. **Green Hydrogen (Electrolysis + Renewables):** Ideally produces near-zero operational emissions if powered by 100% renewable electricity.[4] However, a full lifecycle perspective must account for the carbon intensity of electricity (if grid-connected) and embodied emissions from manufacturing and deploying renewable energy infrastructure (solar panels, wind turbines, hydropower dams) and the hydrogen plant itself. Lifecycle values for hydrogen, including embodied emissions, can range from 0.4 kg CO2e/kg H2 for hydropower, 0.6 kg CO2e/kg H2 for wind, to 2.1 kg CO2e/kg H2 for solar PV, with PV manufacturing emissions being a significant factor. [5] Most GHG emissions for PV/wind electrolysis come from the production of PV panels (90%) and wind turbines (83%). The GH2 Green Hydrogen Protocol sets a threshold of ≤ 1.0 kg CO2e/kg H_2 (average over 12 months), covering key production steps but excluding embodied emissions from infrastructure. This variability within "green" hydrogen highlights that the choice of renewable source matters significantly for the actual lifecycle emissions.

d. **Turquoise Hydrogen:** Yields 2-4 kg CO_2e/kg H_2 from lifecycle emissions.

e. **Fugitive Emissions (H_2):** *Hydrogen (H_2):* Fugitive hydrogen emissions are an emerging concern. While not a direct GHG, H_2 reacts in the atmosphere to indirectly increase the lifetime and warming effect of methane and ozone. Robust monitoring and leak prevention protocols are needed across the hydrogen value chain (production, storage, transport, use), but standardized methodologies are still developing. Accurate and transparent accounting for these non-CO_2 GHGs is essential for credible GHG intensity calculations and ensuring environmental integrity.

The GHG intensity comparison reveals a spectrum of "cleanliness," not a simple binary. Green hydrogen's lifecycle emissions vary significantly based on the renewable source and embodied emissions. Blue hydrogen's "cleanliness" is highly dependent on capture rates and, critically, upstream methane. This means that merely meeting a "low-carbon" threshold might not be sufficient to avoid lock-in if that threshold is not ambitious enough or if it allows for significant residual emissions (e.g., from methane leakage). There is a risk of locking into "good enough" solutions (e.g., blue hydrogen with typical capture rates and unaddressed methane) that prevent the transition to truly "net-zero compatible" solutions (e.g., optimized green hydrogen). The "lowest feasible GHG intensity" criterion implicitly requires continuous re-evaluation as technologies advance and understanding of lifecycle impacts (like H2 fugitives) improves. Furthermore, if the hydrogen economy scales up significantly and fugitive hydrogen emissions are not minimized, the overall climate benefit could be undermined,

[4] Green ammonia - Iberdrola, accessed May 2, 2025

[5] Gan et. Al., 2024, Considering Embodied Greenhouse Emissions of Nuclear and Renewable Power Plants for Electrolytic Hydrogen and Its Use for Synthetic Ammonia, Methanol, Fischer–Tropsch Fuel Production. Environ. Sci. Technol. 2024, 58, 42, 18654–18662

potentially leading to a "hidden lock-in" of indirect warming. This is a critical emerging lock-in risk that could compromise the *net* climate benefit.

Table 6: Comparative Life Cycle GHG Intensity of Hydrogen Production Pathways

Pathway	GHG Intensity Range (kg CO_2-eq/kg H_2)	Key Assumptions	Sources
Grey SMR (No CCS)	10–12 (LCA, cradle-to-gate)	Includes upstream NG supply	IEA (2024a); Patel et al. (2024)
Blue SMR/ATR + CCS	2.8–9.3	Extremely sensitive to capture rate AND upstream CH_4 leakage. Lower bound requires CH_4 leakage <0.2% AND capture >95% — not yet demonstrated at scale.	Patel et al. (2024); Howarth & Jacobson (2021); IEEFA (2023)
Turquoise (Methane Pyrolysis)	0.8–4.0	Depends on energy source for pyrolysis and carbon management	Sánchez-Bastardo et al. (2021)
Green Electrolysis (Hydropower)	0.1–0.4	LCA including embodied emissions	Gan et al. (2024); Hydrogen Council (2021)
Green Electrolysis (Wind)	0.4–0.7	LCA including embodied emissions	Gan et al. (2024); Hydrogen Council (2021)
Green Electrolysis (Solar PV)	1.5–2.5	Higher due to PV manufacturing emissions (~90% of total LCA)	Gan et al. (2024); Silva & Capaz (2025)
Green Electrolysis (Harmonised range)	0.67–1.74	Comprehensive 2025 global review	Adetona et al. (2025)

The GHG intensity comparison reveals a spectrum rather than a binary. Green hydrogen's lifecycle emissions vary significantly based on the renewable source and embodied emissions. Blue hydrogen's climate benefit is highly contingent on near-perfect methane management and CCS performance — conditions not yet demonstrated at scale.

2.5.2| Fugitive Hydrogen Emissions:

Hydrogen (H_2) is not a direct greenhouse gas, but it reacts in the atmosphere to indirectly increase the lifetime and warming effect of methane and tropospheric ozone. The GWP_{100} for hydrogen is 11.6 ± 2.8 (Sand et al., 2023), with the latest global synthesis reporting 11 ± 4 (Wiltshire et al., 2025). For quantification, this methodology applies a GWP_{100} for hydrogen of 14.4, being the upper bound of the 11.6 ± 2.8 estimate of Sand et al. (2023), adopted as a deliberate conservativeness measure and derived at Section 4. Electrolysis production-stage leakage estimates range from 0.2% (steady-state membrane crossover) to a literature-synthesis average of 1.72% when all operational losses are included (Trapani et al., 2025).

Robust monitoring and leak prevention protocols are essential across the hydrogen value chain. If the hydrogen economy scales up significantly and leakage rates are not minimised, the overall climate benefit could be undermined — a “hidden lock-in” of indirect warming.

2.6| Resource Efficiency Assessment

2.6.1| Electricity Consumption

Green hydrogen production is energy-intensive. At the system level (including compression to 30 bar), modern commercial electrolysers consume approximately 48–60 kWh/kg H_2 depending on the technology (IEA, 2025a; IRENA, 2021). If the global hydrogen economy were to scale to replace the 290 billion cubic metres of natural gas and 90 million tonnes of coal equivalent currently consumed for hydrogen production (IEA, 2025a), it would require approximately 3,000–4,000 TWh of renewable electricity annually — roughly equivalent to the entire EU’s electricity consumption. This underscores the importance of prioritising green hydrogen for applications where direct electrification is not feasible, as articulated in the Liebreich Associates Clean Hydrogen Ladder (v4.1; Liebreich, 2024).

2.6.2| Water Consumption

The stoichiometric minimum is 9 kg H_2O per kg H_2. Including purification and cooling, total consumption ranges from 18–30 litres per kg H_2 (Simoes et al., 2024; Newborough & Cooley, 2021). This poses challenges in water-stressed regions with high solar potential (e.g., MENA, parts of Australia, Chile), creating a water-energy-climate nexus. The methodology addresses this through the strict 5% potable water cap and the WRI Aqueduct geographic filter (Section 3.2 of the methodology).

2.6.3| Land Use

Large-scale renewable energy installations require significant land. Solar PV land use intensity ranges from 0.1–10 m²/MWh; wind farms are more land-intensive per MW but allow dual-use of intervening land (Lovering et al., 2022).

Table 7: Resource Consumption Comparison for Low-Carbon Hydrogen Production (Indicative)

Pathway	Primary Energy Feedstock	Electricity Input (kWh/kg H2)	Water Input (t H2O / t H2)	Notes
Grey SMR (No CCS)	Natural Gas	Lower (process heat from NG)	~0.66 (process) + cooling	Water primarily for steam reforming & cooling.

Blue SMR/ATR + CCS	Natural Gas	Moderate (for CCS unit)	Similar to Grey + CCS needs	Additional energy needed for CO_2 capture/compression. Water use similar to grey plus potential CCS needs.
Green Electrolysis (AEL/PEM)	Water	~9.4 - 11	~1.6 - 2.5	High electricity demand for electrolysis/ASU/HB. High purity water needed for electrolysis; includes cooling.
Green Electrolysis (SOEC)	Water (Steam)	Potentially Lower (<9.4)	Similar to AEL/PEM	Higher electrical efficiency possible if waste heat available, but higher degradation.

Note: Values are approximate and vary based on technology specifics, plant scale, and operating conditions. Electricity input for Grey/Blue pathways primarily covers auxiliary equipment unless specified otherwise.

The high water consumption of green hydrogen production, particularly in regions with high renewable potential that are also water-stressed, presents a significant challenge. This creates a water-energy-climate nexus, where a project might be carbon-neutral but exacerbate local water scarcity. This could be deemed an "inefficient use of resources critical for climate change mitigation or other policy objectives". This necessitates a holistic assessment beyond just GHG emissions, focusing on the broader sustainability footprint and requiring robust water management plans. Without such considerations, there is a risk of locking in unsustainable resource practices, even if the carbon footprint is low.

2.7| Lock-in Risk Assessment Summary

According to Requirements for additionality demonstration, Section 6.2, the scale of the activity is a factor to be considered in the lock-in analysis. Large-scale projects inherently amplify the potential consequences of lock-in. Significant capital investment in multi-decade infrastructure creates considerable inertia, making it economically and logistically difficult to pivot to alternative technologies or pathways should they become preferable later. A large-scale green hydrogen plant locks in significant demand for renewable electricity and potentially water resources, influencing the development trajectory of the energy and water systems in the region. The sheer size of these investments means that any misstep in aligning with long-term goals can have major, long-lasting repercussions for national and global decarbonization efforts. Therefore, the larger the scale of the proposed activity, the more critical and rigorous the lock-in risk assessment becomes.

a. **Green Hydrogen:** The primary lock-in risks relate to resource inefficiency (high electricity and water demand) and the potential diversion of renewable resources from more efficient direct uses. The lifecycle GHG intensity, while potentially very low, is sensitive to the renewable source used and the embodied emissions of the infrastructure. Long infrastructure lifetimes necessitate ensuring alignment with evolving energy systems. Furthermore, the indirect warming impact of fugitive hydrogen emissions is an emerging concern that must be managed to ensure the net climate benefit.

b. **Blue Hydrogen:** The primary lock-in risks are its incompatibility with mid-century net-zero goals due to reliance on fossil fuels and residual emissions (imperfect CCS and critical upstream methane leakage), and the long lifetime of the associated infrastructure potentially creating stranded assets. Its climate benefit is highly contingent on near-perfect methane management and CCS performance.

c. **Turquoise Hydrogen:** Risks are similar to blue regarding fossil feedstock dependency and long asset life. Additional uncertainty exists around the management of the solid carbon byproduct and the energy source for pyrolysis.

The "cleanliness spectrum" of hydrogen production, from grey to various shades of green, highlights a critical challenge: merely meeting a "low-carbon" threshold might not be sufficient to avoid lock-in if that threshold is not ambitious enough or if it allows for significant residual emissions (e.g., from methane leakage). This creates a risk of locking into "good enough" solutions that prevent the transition to truly "net-zero compatible" solutions. The criterion of "lowest feasible GHG intensity" implicitly requires continuous re-evaluation as technologies advance and understanding of lifecycle impacts, such as fugitive hydrogen emissions, improves.

The high water consumption of green hydrogen production, particularly in regions with abundant renewable potential that are also water-stressed, presents a significant challenge. This situation creates a water-energy-climate nexus, where a project might be carbon-neutral but simultaneously exacerbate local water scarcity. This could be deemed an "inefficient use of resources critical for climate change mitigation or other policy objectives". This necessitates a holistic assessment beyond just GHG emissions, focusing on the broader sustainability footprint and requiring robust water management plans. Without such considerations, there is a risk of locking in unsustainable resource practices, even if the carbon footprint is low.

The indirect climate impact of fugitive hydrogen emissions is a relatively newer area of concern compared to CO2 or methane. If the hydrogen economy scales up significantly and leakage rates are not minimized, the overall climate benefit could be undermined, potentially leading to a "hidden lock-in" of indirect warming. This means that even "green" hydrogen is not entirely climate-neutral if leakage is high. This necessitates robust monitoring, leak prevention, and potentially new regulatory frameworks to account for and mitigate these indirect effects, which are currently not classified as reportable GHGs under UNFCCC/IPCC. This is a critical emerging lock-in risk that could compromise the net climate benefit of the hydrogen transition.

Table 8: Green Hydrogen Lock-in Risk Assessment Summary against GS4GG Criteria

GS4GG Criterion	Green Hydrogen Assessment	Risk Level	Mitigation via Methodology Applicability Conditions
Creates dependency on fossil fuels	No fossil feedstock. Powered by RE.	**Low**	Dedicated RE supply; grid electricity capped at 10% (Section 3.2); zero-

			emission auxiliaries; methane-based compressors/pipelines prohibited.
Extends lifespan of high-emission infrastructure	Greenfield: new facility, no fossil extension. Brownfield: replaces fossil equipment.	**Low**	Mandatory decommissioning of existing fossil-based H_2 equipment for brownfield (Section 3.3).
Adopts technologies with no decarbonisation pathway	Electrolysis is a core zero-emission H_2 pathway.	**Low**	Electrolyser modularity allows upgrades. Strict exclusion of grey/blue/biomass pathways.
Triggers market/regulatory shifts favouring fossil fuels	Drives demand for RE, supporting RE market growth.	**Low**	Dedicated, additional RE required; prevents diversion of existing clean energy.
Resource efficiency	High electricity and water demand.	**Low–Medium**	5% potable water cap; WRI Aqueduct assessment; desalination energy accounted for within activity boundary.
Technology lifetime	Multi-decade facility; shorter stack lifetimes (5–11 yrs).	**Low**	Stack modularity enables technology upgrades during facility lifetime.
Emissions intensity	Near-zero direct; LCA 0.67–1.74 $kgCO_2$-eq/kgH_2.	**Low**	Strict RE sourcing; embodied emissions accounted as leakage; fugitive H_2 monitored continuously.
Scale	Large-scale projects amplify consequences.	**Low**	Methodology's stringent applicability conditions ensure large-scale projects are inherently low-carbon and resource-efficient.
Availability of alternatives	Green H_2 is the lowest-emission pathway for hydrogen production.	**Low**	Methodology excludes all higher-emission alternatives (grey, blue, biomass).

2.8 | Conclusion and Methodology-Level Determination

2.8.1 | Overall Finding

Green hydrogen production, when compliant with all applicability conditions of the methodology (Section 3), poses a low risk of technology, emissions, or carbon lock-in. This conclusion is supported by the following structural features:

1. The core technology (water electrolysis) creates no dependency on fossil fuel feedstocks.
2. Electrolyser modularity (stack lifetimes of 5–11 years) allows for periodic technology upgrades and efficiency improvements without replacing the entire facility.
3. The mandatory use of dedicated, additional renewable energy prevents diversion of existing clean energy resources.

4. The strict prohibition of fossil backup systems, methane-based compressors, and pipelines eliminates operational fossil dependency.
5. The mandatory decommissioning of existing fossil-based hydrogen equipment for brownfield activities prevents the extension of high-emission infrastructure lifespans.
6. The 5% potable water cap and WRI Aqueduct geographic filter address the water-energy-climate nexus.
7. Embodied emissions from manufacturing new infrastructure are fully accounted for as leakage and amortised over the first crediting period.
8. Fugitive hydrogen emissions are continuously monitored and quantified using the GWP_{100} of 11.6 (Sand et al., 2023).

2.8.2| Methodology-Level Exemption

Based on this comprehensive analysis, the activity developer is not required to conduct a separate activity-level lock-in risk analysis, provided the activity strictly adheres to all applicability conditions defined in Section 3 of the methodology. Compliance with these conditions inherently satisfies the GS4GG lock-in risk criteria.

For the avoidance of doubt, the conditions that discharge the lock-in criteria are those set out in the methodology as adopted, and no others; this determination does not rest on any condition additional to or different from them. In particular it does not rest on a prohibition of grid connection or of emergency fossil backup, both of which the methodology permits within defined and fully accounted limits. The activity developer shall confirm in the PDD that the activity meets all applicability conditions and therefore qualifies for the methodology-level lock-in risk classification of “Low Risk.”

2.8.3| Methodology-Level Determination — Overall Finding

The renewable electricity consumed by an activity under this methodology is subject to the applicability conditions of Section 3, which require dedicated, additional renewable generation with temporal and geographical matching. The methodology's treatment of competition for that renewable electricity, and the basis on which displaced-generation leakage is or is not applied, are addressed in the methodology at section 9 and in the Supplementary Information section on renewable electricity attribution. This lock-in analysis identifies the diversion of renewable electricity from other uses as a category of risk; its quantitative treatment as leakage is determined there and is cross-referenced here rather than duplicated

2.8.4| Guidance: Checklist for VVB Confirmation

The following checklist should be completed in the PDD to confirm lock-in risk compliance. If all conditions are met, the activity qualifies for the methodology-level exemption. If any condition is not met, a detailed activity-level lock-in assessment shall be conducted.

#	Condition	Yes/No
1	Is hydrogen (H_2) production exclusively via water electrolysis (AWE, PEM, SOEC, or AEM)?	
2	Is the electrical energy for all significant process stages demonstrated to originate from Renewable Energy sources as defined in the methodology?	
3	Does the annual consumption of grid electricity not exceed 10% of total annual electricity consumption?	
4	If off-site RE facilities supply the activity, do they meet Origin (COD within 36 months of PIS), Deliverability (same grid region), and Temporal Matching (hourly) criteria?	
5	Is water the sole feedstock for hydrogen production within the activity boundary?	
6	Does the activity comply with the 5% potable water cap AND the applicable WRI Aqueduct BWS classification?	
7	For brownfield retrofits: is the existing fossil-based hydrogen production equipment verifiably decommissioned, destroyed, or rendered permanently inoperable?	
8	Are all auxiliary systems (compression, storage, transport) zero-emission? Is the use of methane-based compressors or pipelines prohibited?	
9	Does the activity comply with all applicable national and local environmental laws and regulations?	
10	Is the produced green hydrogen dispatched exclusively for Eligible End-Uses as defined in Section 3 of the methodology?	

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3.| SECTION 3: BEST AVAILABLE TECHNOLOGY ANALYSIS FOR HYDROGEN PRODUCTION

3.1| Introduction

Hydrogen is increasingly recognised as a pivotal component in the global energy transition and a critical enabler for deep decarbonisation across hard-to-abate sectors — including heavy industry (such as steel and chemicals production), long-distance transportation, maritime shipping, and aviation. Beyond its direct use as a fuel or feedstock, hydrogen facilitates the storage and long-distance transport of renewable energy, thereby mitigating the inherent intermittency of solar and wind power generation and enabling a more resilient energy system (Shaya & Glöser-Chahoud, 2024; Yue et al., 2021).

Global projections underscore the anticipated growth in low-carbon hydrogen production. Under the International Renewable Energy Agency's (IRENA) 1.5°C Scenario — a normative pathway describing what would be required to limit warming to 1.5°C — green and blue hydrogen production would need to reach 125 million tonnes per annum (Mtpa) by 2030 and 523 Mtpa by 2050, requiring an installed electrolyser capacity of 428 GW by 2030 and 5,722 GW by 2050 (IRENA, 2024a). This scale of deployment could contribute to reducing global emissions by 12% by mid-century.

Despite this critical future role, the current global hydrogen landscape remains heavily reliant on conventional, high-emission production methods. Global hydrogen demand reached approximately 100 million tonnes (Mt) in 2024, with low-emissions hydrogen accounting for less than 1 Mt — still under 1% of total production (International Energy Agency [IEA], 2025a). Approximately 98% of all hydrogen produced today originates from carbon-intensive processes. Steam Methane Reforming (SMR) of natural gas is the dominant method, covering approximately two-thirds of dedicated hydrogen production, while coal gasification contributes around 20%, with China alone responsible for 90% of global coal consumption for hydrogen production (IEA, 2025a). In 2023, hydrogen production directly emitted approximately 920 Mt CO_2 (IEA, 2024a). When including upstream and midstream fossil fuel supply chain emissions, total emissions are estimated at 1,100–1,250 Mt CO_2 equivalent. Specifically, unabated natural gas-based production emits 10–12 kg CO_2-equivalent per kilogram of hydrogen (cradle-to-gate), while unabated coal gasification emits 22–26 kg CO_2-equivalent per kilogram (IEA, 2024a). On a direct plant-gate basis (excluding upstream emissions), SMR typically emits 9–10 kg CO_2/kg H_2, while coal gasification results in approximately 18–20 kg CO_2/kg H_2 (IEA, 2023a).

Establishing clear performance benchmarks based on Best Available Technology (BAT) is thus a crucial strategic imperative for achieving global net-zero emissions targets and effectively directing investments towards cleaner hydrogen technologies. These benchmarks serve as a vital reference point for assessing current industrial performance and informing the design and implementation of effective climate policy mechanisms, such as emissions trading systems and carbon crediting frameworks under the Paris Agreement. They are fundamental in ensuring that new investments are compatible with long-term climate goals. This is particularly critical given the long operational lifetimes of industrial assets, including hydrogen production facilities, which can span 20 to 50 years or more. Decisions made today can lock in emissions profiles for decades (Unruh, 2000; Seto et al., 2016). This creates a temporal mismatch, where investments in technologies with residual emissions — even if currently considered "low-carbon" (e.g., blue hydrogen with imperfect carbon capture) — could become misaligned with future, more stringent climate goals. This situation underscores the need for a highly forward-looking approach to BAT selection, prioritising technologies capable of achieving near-zero emissions over their entire lifespan.

For a comprehensive overview of the global hydrogen market, including growth trajectories, commercialisation pathways, and policy drivers, see Section 1.

3.2| Best Available Technology (BAT) Determination Framework

3.2.1| Objectives and Scope

The concept of Best Available Technology (BAT) is central to global industrial emissions regulation and reduction. BAT represents the most effective and advanced stage in the development of activities and their operational methods, indicating techniques that are practically suitable for establishing emission limit values and other permit conditions designed to prevent, or where prevention is not practicable, to reduce emissions and their overall environmental impact.

The primary objective of this BAT analysis for hydrogen production is to identify technologies that are not only economically viable and environmentally sound but also explicitly align with deep decarbonisation goals — specifically, technologies compatible with the long-term temperature objectives of the Paris Agreement, aiming to limit global warming to well below 2°C and pursuing 1.5°C. This objective extends beyond simple emissions reduction to ensure the long-term climate compatibility of investments, especially considering the multi-decade operational lifespan of hydrogen production facilities.

The scope of this BAT analysis is comprehensive, encompassing the entire hydrogen production process. It includes all major current and emerging technologies: Steam Methane Reforming (SMR), Autothermal Reforming (ATR), coal gasification, various forms of electrolysis (Alkaline Water Electrolysis [AWE], Proton Exchange Membrane [PEM], Solid Oxide Electrolysis Cells [SOEC], Anion Exchange Membrane [AEM]), as well as methane pyrolysis (turquoise hydrogen) and biomass gasification. Novel or alternative methods are assessed at their current Technology Readiness Levels (TRL).

3.2.2| Evaluation Criteria for BAT Selection

Drawing from the UNFCCC standard for setting baselines (A6.4-SB005-A002, Version 02.0; UNFCCC, 2024), the selection of BAT for hydrogen production adheres to specific criteria. The BAT approach is applicable when:

a. emissions or removals per unit of output are primarily determined by the specific technology or practice employed; and
b. sufficient and reliable data are available to identify and assess the BAT. If a host Party has already mandated a specific technology as BAT, that definition shall be applied.

The identification of the specific BAT involves a multi-step assessment against the following criteria:

a. **Economic Viability:** This criterion assesses the financial attractiveness and cost-effectiveness of each technology, including Capital Expenditure (CAPEX), Operational Expenditure (OPEX), Levelized Cost of Hydrogen (LCOH), sensitivity to carbon pricing, and payback period. The economic viability of low-carbon pathways, such as green hydrogen, is often not self-sustaining without significant policy intervention, as its cost premium ranges from approximately 60% to over 300% compared with grey hydrogen, depending on the region (IEA, 2025a; Curico, 2025).
b. **Environmental Performance:** This criterion quantifies Greenhouse Gas (GHG) emissions intensity (kg CO_2e/kg H_2), energy efficiency (kWh/kg H_2), resource use (water consumption, land use), and waste and byproduct management. The UNFCCC framework emphasises using technologies with the "lowest feasible greenhouse gas intensity for long-lifetime investments" (UNFCCC, 2024). This criterion is inherently dynamic: what constitutes "lowest feasible" will evolve as technologies advance, implying continuous re-evaluation.
c. **Regulatory Compliance:** This criterion verifies compliance with national environmental regulations (including emissions limits and energy efficiency standards) and alignment with international agreements such as the Paris Agreement, national net-zero targets, and Nationally Determined Contributions (NDCs). The economic context, including carbon pricing mechanisms, is explicitly considered as a critical factor influencing economic viability and technology selection.
d. **Technical Feasibility:** This criterion evaluates scalability, technological maturity (Technology Readiness Level), the availability of necessary infrastructure, and operational reliability and maintenance requirements — including the intermittency management challenges specific to green hydrogen.
e. **Social and Strategic Factors:** This criterion considers broader societal and national implications: contribution to job creation and local economic impact, effects on energy security and import dependence, public acceptance, and alignment with national energy transition strategies and broader plans for decarbonization and energy system transformation.

BAT can be defined in three ways:

a. accepting host Party recommendations approved by the Supervisory Body;
b. defining BAT within the methodology using robust data; or
c. providing a procedure for activity developers to identify BAT themselves.

The geographical scope for BAT determination shall be clearly defined and justified. Where data is uncertain or incomplete, a conservative approach is warranted in setting benchmarks.

3.3| Candidate Technologies for Hydrogen Production

3.3.1| Conventional Hydrogen Production Technologies

These methods are mature and widely deployed, with BAT determination focusing on optimizing energy efficiency and reducing emissions within existing configurations..

a. **Steam Methane Reforming (SMR):** SMR is the most prevalent hydrogen production method globally, accounting for approximately two-thirds of dedicated hydrogen production (IEA, 2025a). The process utilises natural gas (methane) as both feedstock and energy source: methane reacts with steam to produce hydrogen (H_2) and carbon monoxide (CO), followed by a water-gas shift reaction generating additional H_2 and carbon dioxide (CO_2). SMR is a technologically mature and highly optimised process at Technology Readiness Level (TRL) 9. On a plant-gate basis (direct emissions only), SMR typically emits 9–10 kg CO_2/kg H_2 (IEA, 2024a; Capodaglio et al., 2024). When upstream and midstream emissions are included, the lifecycle intensity rises to 10–12 kg CO_2-eq/kg H_2 for pipeline gas (IEA, 2024a), and 12.3–13.9 kg CO_2-eq/kg H_2 in comprehensive LCA studies (Patel et al., 2024). The direct-only BAT for efficient, modern large-scale SMR is approximately 8.5–9.5 kg CO_2/kg H_2, representing the performance of top-tier operational facilities. The energy demand for natural gas in SMR without CO_2 capture is approximately 44.5 kWh/kg H_2 (IEA, 2021).
b. **Autothermal Reforming (ATR):** ATR combines partial oxidation with steam reforming, generating the necessary heat internally, reducing reliance on external heating. It is often considered more energy-efficient than SMR, particularly for new, large-scale plants. ATR's direct emissions profile is similar to SMR, but it is generally more suitable for carbon capture due to the higher concentration of CO_2 in its off-gas stream. The energy demand for natural gas in ATR is around 41 kWh/kg H_2 (IEA, 2021). ATR technology is mature (TRL 9), with over 25 commissioned units and more than 300 years of cumulative operational experience.
c. **Coal Gasification:** This method is particularly prevalent in countries with abundant coal reserves — most notably China, which accounts for approximately 90% of global coal consumption for hydrogen production (IEA, 2025a). Coal gasification is a mature technology (TRL 9) but is significantly more carbon-intensive than SMR, with direct emissions of approximately 18–20 kg CO_2/kg H_2 (IEA, 2023a). The total lifecycle emissions (cradle-to-gate) are 22–26 kg CO_2-eq/kg H_2 (IEA, 2024a). The energy demand

for coal gasification without CO_2 capture is approximately 57 kWh/kg H_2, with an additional ~0.7 kWh/kg H_2 for electricity (IEA, 2021).

3.3.2| Low-Carbon Hydrogen Production Technologies:

a. **Blue Hydrogen (SMR/ATR with Carbon Capture and Storage - CCS):** This pathway integrates Carbon Capture, Utilisation, and Storage (CCUS) technology to capture a significant portion of the CO_2 generated during SMR or ATR. Technology providers target capture rates exceeding 90%, with ATR designs potentially achieving up to 99% on concentrated process CO_2 streams. However, a 90% carbon capture rate does not equate to a 90% emissions reduction, as additional energy is required for capture and supply chain emissions persist (Howarth & Jacobson, 2021). Real-world capture rates at operational blue hydrogen facilities have consistently fallen short of targets, with reported rates of 35–80% of total facility emissions (Institute for Energy Economics and Financial Analysis [IEEFA], 2023). No new blue hydrogen projects commenced production in 2024 (IEA, 2025a).

   The overall climate benefit is highly sensitive to the actual CO_2 capture rate, the energy penalty, the permanence of CO_2 storage, and — critically — upstream methane emissions from the natural gas supply chain. Blue hydrogen can yield very low greenhouse gas emissions only if methane leakage emissions do not exceed 0.2%, with close to 100% carbon capture — conditions not yet demonstrated at commercial scale (IRENA, 2022). The lifecycle emissions for blue hydrogen (SMR-CCS) vary significantly: from 2.78 kg CO_2-eq/kg H_2 for pipeline gas with high capture rates to 9.3 kg CO_2-eq/kg H_2 for LNG-sourced gas, with some studies reporting 7.6 kg CO_2-eq/kg H_2 (Patel et al., 2024). Recent analysis shows blue hydrogen assets deployed within the next three decades are "likely to be significantly underutilised" and face "a substantial risk" of becoming stranded assets (Fazeli et al., 2025). The energy demand for SMR with 93% CO_2 capture is approximately 49 kWh/kg H_2 for natural gas and 0.8 kWh/kg H_2 for electricity (IEA, 2021).

b. **Green Hydrogen (Water Electrolysis using Renewable Energy):** This pathway produces hydrogen through water electrolysis powered exclusively by renewable energy sources. The core electrolysis technologies — Alkaline Water Electrolysis (AWE) and Proton Exchange Membrane (PEM) — are commercially mature at TRL 9, as demonstrated by the commissioning of the 500 MW Envision Chifeng project in Inner Mongolia in July 2025 (IEA, 2025a). Solid Oxide Electrolysis (SOEC) stands at TRL 7–8, and Anion Exchange Membrane (AEM) at TRL 5–6 (IEA, 2025b).

   Direct CO_2 emissions from green hydrogen production are virtually zero (IEA, 2024a). However, cradle-to-gate LCA emissions — accounting for the manufacturing and deployment of renewable energy infrastructure — range from 0.1 to 0.7 kg CO_2-eq/kg H_2 when powered by dedicated wind or hydropower, rising to 1.5–2.5 kg CO_2-eq/kg H_2 for solar PV due to embodied emissions from panel manufacturing (Gan et al., 2024; Shaya & Glöser-Chahoud, 2024). A comprehensive 2025 global review reports harmonised green hydrogen lifecycle emissions of 0.67–1.74 kg CO_2-eq/kg H_2 (Adetona et al., 2025). Most LCA emissions for PV/wind electrolysis originate from the manufacturing of PV panels (~90% of total) and wind turbines (~83%) (Silva & Capaz, 2025).

The overall electricity demand for low-temperature water electrolysis is approximately 50 kWh/kg H_2 at system level, including compression to 30 bar (IEA, 2021). Modern commercial systems operate at 48–55 kWh/kg H_2 for AWE and 50–60 kWh/kg H_2 for PEM at the >10 MW scale. SOEC can achieve 37–45 kWh/kg H_2 when integrated with waste heat. Long-term targets remain below 45 kWh/kg H_2 for AWE/PEM and below 40 kWh/kg H_2 for SOEC by 2050 (IRENA, 2021).

Green hydrogen production requires substantial quantities of high-purity water. The stoichiometric minimum is 9 kg H_2O per kg H_2. Including water purification and process cooling, total consumption ranges from 18–30 litres per kg H_2 — with PEM systems typically at the lower end (~18–20 L/kg) and alkaline systems with evaporative cooling at the upper end (~22–30 L/kg) (Simoes et al., 2024; Newborough & Cooley, 2021).

3.3.3| Emerging Pathways:

a. **Turquoise Hydrogen (Methane Pyrolysis):** This process decomposes methane into hydrogen gas and solid carbon at high temperatures. It avoids direct CO_2 emissions, as carbon is produced in solid form. Viability depends on the energy source for pyrolysis and the effective management of the solid carbon co-product. The TRL is generally 4–6 (pilot stage), although some plasma pyrolysis technologies have reached TRL 8–9. LCA emissions can be as low as 0.8–1.1 kg CO_2-eq/kg H_2 when renewable electricity is used (Sánchez-Bastardo et al., 2021; Parkinson et al., 2019).

b. **Biomass Gasification.** This pathway is at TRL 5–7. When combined with CCS, it can achieve negative CO_2 emissions, ranging from -15 to -22 kg CO_2-eq/kg H_2 (Rosa & Mazzotti, 2022). It is not yet commercially viable for large-scale hydrogen production.

c. **Other Novel Methods.** Research is ongoing into photoelectrochemical processes, solar thermochemical cycles, biological hydrogen production, and natural geologic hydrogen ("white hydrogen"). These technologies are at TRL 1–4 and are not yet viable candidates for BAT determination.

3.3.4| Electrolyser Technologies - Ancillary Technologies

The choice of electrolyser technology significantly impacts the efficiency, cost, and scalability of green hydrogen production.

a. **Alkaline Water Electrolysers (AWE):** The most mature and commercially deployed technology (TRL 9). Robust and suitable for large-scale installations, utilising affordable nickel-based electrodes.

b. **Proton Exchange Membrane (PEM)** Electrolysers: A rapidly maturing technology (TRL 9) offering higher operating current densities, compact designs, and superior dynamic response for coupling with intermittent renewable energy. However, PEM requires platinum group metals (PGMs) as catalysts, increasing CAPEX by 15–30% compared with AWE.
c. **Anion Exchange Membrane (AEM)** Electrolysers: An emerging technology (TRL 5–6) showing promise for cost-effectiveness, potentially without PGM catalysts. No commercial AEM systems at >1 MW have been deployed as of 2025; modelled cost estimates at the 1 MW scale suggest $444–931/kW, but these are unverified.
d. **Solid Oxide Electrolysis Cells (SOEC):** Operating at 700–850°C, SOEC offers higher electrical efficiencies, particularly when integrated with waste heat sources. TRL 7–8. Stack lifetime is improving, with optimisation models indicating >50,000 hours is achievable (ScienceDirect, 2025a).

A critical observation across these technologies is the inverse relationship between technological maturity (TRL) and environmental performance. The most mature technologies (SMR, coal gasification) are the most carbon-intensive. Low-carbon and emerging technologies offer significantly lower emissions but face scale-up and integration challenges. Furthermore, the definition of "clean" hydrogen is highly nuanced, profoundly influenced by upstream emissions (e.g., methane leakage for blue hydrogen) and embodied emissions from manufacturing renewable energy infrastructure. Robust, standardised LCA methodologies — such as ISO 19870 or the DOE 45VH2-GREET model — are essential for credible assessment (Osman et al., 2024).

3.4| Comparative Analysis of Hydrogen Production Technologies

A detailed comparison of candidate technologies is essential for identifying the Best Available Technology (BAT) for hydrogen production. This analysis evaluates each technology against the established criteria, considering global performance, regional specificities, and the influence of policy and economic factors.

3.4.1| Global Technology Mix and Emission Performance

Understanding the current performance landscape of the global hydrogen industry is fundamental to establishing meaningful BAT benchmarks. This involves analyzing the prevalent production technologies, their associated emission intensities, and the potential offered by best practices and emerging low-carbon pathways.

Global hydrogen demand reached 100 million tonnes (Mt), with low-emissions hydrogen contributing less than 1 Mt, indicating a profound reliance on conventional methods. The majority of dedicated hydrogen production (approximately two-thirds) is met by natural gas via SMR, while around 20% comes from coal gasification, predominantly in China (which accounts for 90% of global coal consumption for hydrogen production). In Europe, for instance, total hydrogen production capacity in 2022 was around 11.5 Mt, with reforming technologies (SMR, POX) dominating at 68.4%, whereas water electrolysis constituted a mere 0.4% of the operational capacity.

The variation in feedstocks and plant efficiencies leads to a wide range of emission intensities globally. The following table provides a comparative overview of hydrogen production technologies, including their energy intensity, direct emissions, and typical life cycle assessment (LCA) emissions

Table 9: Comparative Hydrogen Production Technologies & Emission Performance

Technology Pathway	Feedstock	Energy Intensity (kWh/kg H_2)	Average Direct Emissions (kg CO_2/kg H_2)	BAT Direct Emissions (kg CO_2/kg H_2)	Typical LCA Emissions (kg CO_2-eq/kg H_2)	TRL
SMR (NG)	Natural Gas	~44.5	~9.5–10.0	~8.5–9.0	10–12 (pipeline NG); 12.3–13.9 (incl. LNG)	9
Coal Gasification	Coal	~57	~18–20	~18 (efficient IGCC); see Section 4 and note below	22–26	9
Blue H_2 (SMR + CCS)	Natural Gas	~49 (NG), ~0.8 (Elec)	<0.1–0.2 (with >95% capture)	<0.1–0.2 (with >95% capture)	2.78–9.3 (sensitive to capture rate & CH_4 leakage)	8–9
Blue H_2 (ATR + CCS)	Natural Gas	~41 (NG)	<0.1–0.2 (with >95% capture)	<0.1–0.2 (with >95% capture)	2.43–3.23 (sensitive to capture rate & CH_4 leakage)	8–9
Green H_2 (Electrolysis, RE)	Water, RE Electricity	~50 (system level)	~0	~0	0.1–2.5 (dependent on RE source)	9 (AWE/PEM); 7–8 (SOEC)
Methane Pyrolysis	Natural Gas	Not detailed	~0 (solid carbon)	~0 (solid carbon)	0.8–1.1 (with RE for pyrolysis)	4–6
Biomass Gasification (+ CCS)	Biomass	Not detailed	Not detailed	Not detailed	-15 to -22 (with CCS)	5–7

Notes: Average Direct Emissions represent the operational fleet performance. BAT Direct Emissions represent the performance of the most efficient, modern facilities. LCA emissions are cradle-to-gate. For blue hydrogen, the lower LCA bound requires methane leakage <0.2% AND CO_2 capture >95% — conditions not yet demonstrated at commercial scale (IRENA, 2022; Howarth & Jacobson, 2021). Sources: IEA (2024a); IEA (2021); Patel et al. (2024); Capodaglio et al. (2024); Elgowainy et al. (2024); Henriksen et al. (2024).

The significant difference between average global performance and BAT levels, particularly for natural gas reforming, highlights a substantial opportunity for near-term emission reductions through the diffusion of existing efficient technologies and practices. Furthermore, the variability and context-dependency of low-carbon pathway performance, especially concerning upstream emissions for blue hydrogen and electricity sources for green hydrogen, necessitate careful, regionally specific assessment when defining future BAT benchmarks.

3.4.2| Regional and Country-Specific BAT Analysis and Benchmarking

Applying the BAT principles and criteria outlined above requires a nuanced analysis tailored to the specific circumstances of major hydrogen-producing regions and countries. Factors such as dominant feedstock, age and efficiency of the existing industrial base, national climate policies and targets (NDCs), energy costs, infrastructure availability (e.g., for CCS or renewables), and economic conditions significantly influence what constitutes the Best Available Technology in a given location.

The following table provides an overview of hydrogen production in key regions and countries, including primary feedstocks, dominant technology, estimated average emission intensity, and key policy drivers:

Table 10: Regional/Country Hydrogen Production Overview

Region/Country	Primary Feedstock	Dominant Technology	Est. Avg. Emission Intensity (kg CO_2-eq/kg H_2, LCA)	Key Policy Drivers
China	Coal (~60% domestic), NG	Coal Gasification, SMR	High (~22–26 for coal; ~10–12 for NG)	Dual Carbon Goals (Peak <2030, Neutrality 2060), Green H_2 Promotion
India	NG, Naphtha, Oil	SMR	Moderate (~10–12)	Net Zero 2070, National Hydrogen Mission (5 Mtpa green H_2 by 2030)
USA	NG (~97–100%)	SMR	Low-Moderate (~10–12)	IRA 45V (phased out by Jan 2028 per P.L. 119-21), Hydrogen Hubs
EU	NG (dominant)	SMR	Low-Moderate (~10–12)	Fit for 55, EU ETS, CBAM, RED III (RFNBOs), European Hydrogen Bank
Russia	NG (~100%)	SMR	Moderate (~10–12)	Low-Carbon Strategy, Hydrogen Concept, Export Focus
Middle East (KSA, UAE, Oman)	NG (~100%)	SMR	Low (~10–12)	Net Zero Targets, Economic Diversification, Export Hub Ambitions
Canada	NG (dominant)	SMR	Moderate (~10–12)	Hydrogen Strategy, ITCs for CCUS/Clean Tech

Australia	NG/Coal (varies)	SMR	Moderate (~10–12)	National Hydrogen Strategy, Hydrogen Headstart
Japan/South Korea	NG, By-product	SMR, By-product H_2	Moderate (~10–12)	Decarbonisation goals, Import reliance, Advanced Electrolysis

Note: LCA intensity estimates include typical upstream emissions. Sources: IEA (2024a); IEA (2025a); national hydrogen strategies as referenced in Section 1.

This regional analysis highlights that while efficient SMR represents a global conventional BAT, the transition pathway and the definition of low-carbon BAT are highly dependent on national policies, resource endowments, and economic factors. Policies like the US IRA and the EU's Fit for 55 package are actively shaping the economic feasibility and therefore the BAT landscape, accelerating the shift towards blue and/or green hydrogen in those jurisdictions. In contrast, countries like China and India are driven by a combination of climate goals, energy security concerns, and the need to decarbonize large, existing fossil-based industries, leading to strong pushes for green hydrogen.

3.4.3| Performance of Low-Carbon Pathways

Two primary pathways are emerging for near-zero emission hydrogen production: blue hydrogen (conventional routes with CCS) and green hydrogen (electrolysis with renewable power).

a. **Blue Hydrogen (SMR/ATR + CCS):** Technology providers claim high capture rates (up to 99%+) on concentrated process CO_2 streams. However, the lifecycle footprint is highly sensitive to the actual CO_2 capture rate and upstream methane emissions. Far from being universally low-carbon, a landmark peer-reviewed analysis demonstrated that when accounting for a realistic 3.5% methane leakage rate and using GWP_{20}, blue hydrogen emissions are only 9–12% lower than grey hydrogen (Howarth & Jacobson, 2021). IRENA has stated: "If new [blue] plants and assets are built to operate on fossil fuels, they will lock in billions of tonnes of greenhouse gas emissions and risk becoming stranded in the journey to net zero" (IRENA, 2022). Economic modelling confirms that blue hydrogen assets face a substantial risk of stranding as green hydrogen costs decline (Fazeli et al., 2025).

   Blue hydrogen is generally less expensive than green hydrogen, with an LCOH of approximately \$2.00–\$4.00/kg — a cost premium of around 40% over grey hydrogen (Curico, 2025). Its viability depends heavily on affordable natural gas and CO_2 transport and storage infrastructure. Current global blue hydrogen production remains minimal, with no new projects commencing production in 2024 (IEA, 2025a).

b. **Green Hydrogen (Electrolysis + Renewable Power):** Direct emissions from the production process are virtually zero. The cradle-to-gate LCA emissions depend on the electricity source: dedicated wind or hydropower yields 0.1–0.7 kg CO_2-eq/kg H_2, while solar PV yields 1.5–2.5 kg CO_2-eq/kg H_2 due to embodied emissions from panel manufacturing (Gan et al., 2024). A comprehensive harmonised review reports green hydrogen emissions of 0.67–1.74 kg CO_2-eq/kg H_2 (Adetona et al., 2025).

Green hydrogen production costs are significantly higher than grey hydrogen. The LCOH varies substantially by region: $4.00–$8.00/kg in Western markets (US, EU, Australia), and $2.50–$5.00/kg in China, where renewable electricity, electrolyser costs, and the cost of capital are substantially lower (IEA, 2025a). Despite the cost challenge, FID-approved projects could deliver 4.2 Mtpa by 2030, representing a fivefold increase from 2024 levels (IEA, 2025a). Only approximately 9% of the announced project pipeline has reached FID (IEA, 2025a), indicating a persistent "investment chasm."

3.5 | Financial and Economic Landscape

The transition to low-carbon hydrogen is fundamentally driven by economic considerations, as new technologies **shall** compete with decades of optimization in conventional production. A detailed financial analysis is essential to understand the current cost landscape, identify key drivers, and assess the viability of future investments.

3.5.1 | Cost Structure Overview

A fundamental observation is the "CAPEX vs. OPEX shift" in the decarbonisation of hydrogen production. Conventional production is inherently OPEX-heavy, with natural gas prices accounting for up to 90% of production costs. Green hydrogen production shifts this burden towards upfront capital investment in renewable energy and electrolyser capacity, offering greater long-term price stability but requiring robust financing mechanisms.

Electrolyser system costs have bifurcated sharply between Chinese and non-Chinese markets. In 2024, the total installed cost outside China was USD 2,000–2,600/kWel, compared with USD 600–1,200/kWel in China (IEA, 2025a). In Europe, 2025 alkaline CAPEX was approximately €2,075/kWel and PEM approximately €2,196/kWel (European Hydrogen Observatory, 2026). China accounts for nearly 60% of global electrolyser manufacturing capacity, with an existing manufacturing capacity of ~20 GW/yr — significantly above current demand of ~2 GW in 2024 (IEA, 2025a). Strong momentum in the Chinese market contrasts with prospects for manufacturers elsewhere, which are experiencing reductions in revenue and increased financial losses, with several bankruptcies and acquisitions reported in 2024–2025.

Table 31: Comparative Hydrogen Production Costs (Current & Projected LCOH)

Pathway	Current LCOH (USD/kg H_2)	Projected LCOH 2030 (USD/kg H_2)	Cost Premium over Grey	Key Cost Drivers
Grey Hydrogen (SMR)	$1.00–$2.50	N/A (Baseline)	N/A	Natural gas price (up to 90% of cost)
Blue Hydrogen (SMR/ATR + CCS)	$2.00–$4.00	$1.50–$3.50	~40–100% over grey	NG price, CO_2 capture/storage costs

Green Hydrogen (Western markets)	\$4.00–\$8.00	\$2.50–\$5.00	~160–400% over grey	RE electricity price, Electrolyser CAPEX
Green Hydrogen (China)	\$2.50–\$5.00	\$1.50–\$3.00	~100–200% over grey	Lower RE costs, electrolyser costs, cost of capital

Sources: Curico (2025); IEA (2025a); Glenk & Reichelstein (2022).

3.5.2| Investment Viability

Capital spending on low-emissions hydrogen projects reached USD 4.3 billion in 2024, an 80% increase from 2023. Based on recent FIDs, spending could rise to nearly USD 8 billion in 2025, with electrolysis expected to account for 80% (IEA, 2025a). Major announced projects underscore the significant capital requirements: the NEOM Green Hydrogen Project represents a total investment of \$8.4 billion, targeting 2 GW of electrolysis capacity and commercial operations by 2027 (IEA, 2025a).

Despite these large-scale announcements, a notable "investment chasm" persists. While the project pipeline for low-emissions hydrogen totals 37 Mtpa potential capacity by 2030, only approximately 9% has reached FID — up from 4% in 2024 (IEA, 2025a). Cancellations and delays reduced the pipeline from 49 Mtpa (GHR 2024) to 37 Mtpa (GHR 2025). The primary barriers remain: high perceived risk, difficulty securing firm long-term offtake agreements (only 12% of planned 2030 green hydrogen production has a secured buyer), and macroeconomic headwinds (IRENA, 2024b).

3.5.3| Sensitivity to Policy

Policy interventions are consistently identified as the most critical factor in bridging the cost gap:

- **Carbon Pricing:** A carbon tax of approximately €100–300/tCO_2 would be required for green hydrogen to achieve price parity with grey hydrogen in most markets (Agora Energiewende & Guidehouse, 2021). Current carbon prices in most jurisdictions are substantially below this level.
- **US Inflation Reduction Act (IRA) — Section 45V**: The IRA's 45V clean hydrogen production tax credit (up to \$3.00/kg for the lowest lifecycle emissions tier) had final implementing regulations published in January 2025 (Federal Register, 2025). However, the "One Big Beautiful Bill Act" (Public Law 119-21, signed July 4, 2025) shortened the 45V eligibility window, requiring facilities to begin construction before January 1, 2028 — five years earlier than the original 2033 deadline. This curtailment of the most generous global hydrogen incentive underscores the policy risk facing the sector.
- **EU Hydrogen Bank:** The European Hydrogen Bank provides fixed premium payments through competitive auctions, with its first auction (November 2023) awarding €720 million at prices up to €4.50/kg, and a second auction for €1.2 billion launched in 2024.

- **Other Policies:** China's Dual Carbon Goals, India's National Hydrogen Mission (5 Mtpa green H_2 by 2030), Australia's Hydrogen Headstart programme ($2/kg refundable offset), and Japan's Contracts for Difference (CfD) mechanism are all shaping regional BAT trajectories.

3.6| Benchmark Emission Factors

Based on the preceding analysis of global performance and regional BAT assessments, this section proposes specific benchmark emission factors for hydrogen production. These benchmarks aim to reflect achievable performance based on BAT, consider regional contexts, and provide a basis for driving decarbonization efforts, potentially within frameworks of the Paris Agreement or national regulatory schemes. The proposed benchmarks are presented on a cradle-to-gate LCA basis where data allows, acknowledging that system boundaries and LCA methodologies can introduce variability. Where LCA data is sparse or highly variable, benchmarks may lean more heavily on direct emission BAT values plus a standardized estimate for upstream emissions.

3.6.1| Proposed Benchmarks

Given significant regional variations, a single global benchmark is inappropriate. Regionally differentiated benchmarks are proposed to reflect current best practices. The benchmarks are presented on two bases: (a) direct emissions at the plant gate, and (b) indicative cradle-to-gate lifecycle emissions for informational context.

Table 12: Recommended Benchmark Emission Factors (tCO_2e/tH_2, Cradle-to-Gate LCA)

Region/Country	BAT Pathway Reflected	Direct Emissions (tCO_2/tH_2)	Upstream Emissions (tCO_2e/tH_2)	Indicative LCA Benchmark (tCO_2e/tH_2)
Global Reference	Efficient SMR (NG)	8.5-9.0	~2.3-3.9 for pipeline NG	~10.8-12.9
China (coal)	Efficient Coal Gasification	18.0	Variable (coal mining)	~22 -26
India	Efficient SMR/Naphtha	8.5-9.0	2.3-3.9	~10.8-12.9
USA	Efficient SMR	8.5-9.0	2.3-3.9	~10.8-12.9
EU	Efficient SMR (per IED BREFs)	8.5-9.0	2.3-3.9	~10.8-12.9
Middle East	Efficient SMR (NG)	8.5-9.0	2.3-3.9	~10.8-12.9
Rest of World	Efficient SMR (NG)	8.5-9.0	2.3-3.9	~10.8-12.9

Sources: IEA (2024a); IEA (2023a); Patel et al. (2024); Hydrogen Council (2021); Elgowainy et al. (2024). Notes: Direct emissions reflect BAT performance. The methodology's crediting baseline (Section 7, eq.1–2) deliberately uses the conservative direct-emissions-only BAT value, explicitly excluding upstream methane emissions. This exclusion is a deliberate conservativeness choice — by excluding upstream emissions that contribute 2.3–3.9 tCO_2-eq/tH_2, the crediting baseline is set lower than the full LCA baseline, yielding fewer credits and protecting environmental integrity. For the full methodology default values, see Section 4 of this SI..

3.7 | Selection of Best Available Technology (BAT)

3.7.1 | Selection Criteria and Decision Rule

Based on the comprehensive comparative analysis, BAT is selected by identifying the technology that satisfies: Economic Viability, Environmental Soundness, Regulatory Compliance, and Technical Feasibility. Per Paragraph 7.1.9 of the GS4GG Methodology Standard, when two candidate technologies each meet a different set of these criteria, the technology with the lowest GHG emissions shall be chosen — explicitly prioritising environmental performance.

3.7.2 | Decision for BAT Selection (Paragraph 7.1.9 of the GS4GG Methodology)

A specific decision rule applies when evaluating two candidate technologies that each meet a different set of the primary criteria. If one technology satisfies the criteria for Economic Viability, Regulatory Compliance, and Technical Feasibility, and another technology satisfies the criteria for Environmental Soundness, Regulatory Compliance, and Technical Feasibility, then the technology with the lowest GHG emissions shall be chosen.1 This requirement explicitly prioritizes environmental performance (lowest GHG emissions) when economic viability and environmental soundness are the differentiating factors between two otherwise compliant and feasible technologies. This ensures that the selection process consistently drives towards the most climate-aligned outcome.

Table 13: BAT Selection Criteria Compliance for Identified Emerging/Future BAT

Region/Country	Current BAT	Economic Viability	Environmental Performance	Regulatory Compliance	Technical Feasibility	Social/Strategic
Global (NG regions)	Efficient SMR (~8.5–9.0 tCO_2/tH_2 direct)	Established, varies with feedstock price	Achieves lower emissions than average SMR fleet	Meets national regulations	TRL 9, widely deployed	Energy security, job creation
China	Efficient Coal Gas (~14–15 direct) / Efficient SMR (~8.5–9.0 direct)	Economically viable as improvement over fleet average	Improvement over average	Aligns with Dual Carbon Goals	TRL 9	Energy security, pollution reduction

India	Efficient SMR (~8.5–9.0 direct)	Established technology	Continuous improvement	Aligns with NHM	TRL 9	Energy security, import reduction
USA	Efficient SMR (~8.5–9.0 direct)	Viable given NG availability	Better than fleet average	Meets existing standards	TRL 9	Energy security, job creation
EU	Efficient SMR (~8.5–9.0 direct)	Established industry	High energy efficiency	Compliant with IED/BREFs	TRL 9	Industrial competitiveness
Russia	Efficient SMR (~8.5–9.0 direct)	Viable given NG availability	Ongoing modernisation	Compliant with Russian federal environmental regulations	TRL 9	Export diversification
Middle East	Efficient SMR (~8.5–9.0 direct)	Viable given low-cost gas	Low environmental impact	Less stringent domestic policies; aware of export market requirements	TRL 9	Export hub ambitions
Canada	Efficient SMR (~8.5–9.0 direct)	Viable given low-cost gas	Low environmental impact	Aligned with Net-Zero Accountability Act	TRL 9	Export focus
Australia	Efficient SMR (~8.5–9.0 direct)	Viable given NG availability	Efficient SMR	Aligns with National H_2 Strategy	TRL 9	Export focus
Japan/S. Korea	Efficient SMR / By-product H_2	Viable for current operations	Focus on advanced electrolysis for future	Aligns with national H_2 strategies	TRL 9	Import reliance, tech leadership

For the long-term, the emerging BAT pathways are shifting towards **Green Hydrogen (Water Electrolysis using Renewable Energy)** across most regions, driven by stringent decarbonisation targets, evolving policy landscapes, and decreasing renewable energy costs. Countries with abundant renewable resources (e.g., Australia, India, Middle East, Chile) are strongly pursuing green hydrogen. Those with significant natural gas reserves and CO_2 storage potential (e.g., USA, Middle East) are also developing blue hydrogen, though the stranded asset risk (Fazeli et al., 2025) and the curtailment of US 45V support (P.L. 119-21) have weakened the long-term case for blue hydrogen investment.

3.8| Conclusions and Recommendations

3.8.1| Outcome of BAT Determination

The current BAT for conventional hydrogen production across virtually all geographies is Efficient SMR at approximately 8.5–9.0 kg CO_2/kg H_2 (direct emissions only, excluding upstream methane). For China's coal-dominant regions, the current BAT is Efficient Coal Gasification at approximately 18.0 kg CO_2/kg H_2 direct. These benchmarks represent the performance of the most efficient operational facilities, not fleet averages.

3.8.2| Recommendation for Methodology Application:

This analysis recommends that the identified BAT for each geography be adopted as the default selection. Activity developers applying this methodology are exempted from conducting their own detailed BAT analysis for the initial crediting period and may apply the identified BAT values.

This recommendation is justified by the comprehensive nature of this analysis, which has evaluated the current technological landscape, economic viability, regulatory compliance, and technical feasibility across global, regional, and country levels. This analysis will be updated per the methodology's update schedule (every 3 years) or earlier if significant technological advancements warrant re-evaluation. Developers may conduct their own BAT analysis to explore activity-specific nuances or demonstrate a more ambitious baseline.

3.8.3| Reconciliation with Methodology Crediting Baseline

The methodology's crediting baseline (Section 7, eq.1–2) uses the direct-emissions-only BAT values established in Section 4 of this SI: - SMR: **8.5 tCO_2/tH_2** - Coal Gasification: **18.0 tCO_2/tH_2** (see Section 4 for detailed derivation) - Naphtha Reforming: 6.3 tCO_2/tH_2. These values are deliberately conservative — set at the lower end of the BAT range and explicitly excluding upstream methane emissions. This ensures the crediting baseline is approximately 20–30% below the full lifecycle baseline, yielding fewer credits. The single crediting value for SMR is 8.5 tCO_2/tH_2; the 8.5–9.0 range used elsewhere in this Section is the analytical BAT range, of which the lower bound is adopted for crediting. The naphtha value of 6.3 tCO_2/tH_2 is an energy-allocated figure for refinery catalytic reforming and its treatment, including the eligibility of co-product hydrogen, is determined at Section 4.

3.9| References

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4.| SECTION 4: DETERMINATION OF AMBITIOUS BENCHMARK

4.1 | Summary

This section establishes clear, data-driven baseline performance benchmarks for the primary unabated hydrogen production technologies that constitute the vast majority of the current global supply. The analysis focuses specifically on defining the direct emissions at the production facility (plant-gate basis), creating a robust and conservative reference point for the industry's likely baseline scenario.

Following a systematic, stepwise methodology consistent with international best practices — specifically the UNFCCC A6.4-SB005-A002 standard (UNFCCC, 2024) and the EU Industrial Emissions Directive BAT Reference Documents (BREFs) — this section identifies the performance of the Best Available Technology (BAT) for each major unabated production pathway. By using the most efficient segment of the existing operational fleet as the reference, the established benchmarks are intentionally ambitious, ensuring that only significant environmental improvements generate carbon credits.

The key findings of this analysis are the direct emission benchmarks for each technology:

a. **Steam Methane Reforming (SMR): 8.5 tCO_2/tH_2**

b. **Coal Gasification: 18.0 tCO_2/tH_2**

c. **Naphtha Reforming: 6.3 tCO_2/tH_2**

These benchmarks represent direct emissions from the production process itself — i.e., process CO_2 from the reforming/gasification reaction plus combustion CO_2 from fuel burned for process heat. Upstream emissions from fossil fuel extraction, processing, and transport are quantified separately and are **deliberately excluded** from the crediting baseline. This exclusion is a conservativeness choice: by omitting upstream emissions (which add 2.3–3.9 tCO_2-eq/tH_2 for natural gas and 4.8–7.2 tCO_2-eq/tH_2 for coal), the baseline is set approximately 20–30% below the full lifecycle value, yielding fewer credits and protecting environmental integrity.

These benchmarks shall serve as a cap: if a country's performance data for its best-performing facilities exceeds this default value, the default shall be applied. Furthermore, if no plants in a specific country meet the stringent criteria (e.g., commissioned post-2020, non-CCS), these default global values shall be applied.

Country-specific benchmarks reflect regional feedstock dominance. For instance, the United States and Europe are benchmarked at 8.5 tCO_2/tH_2 (reflecting natural gas SMR BAT), while China's coal-based production is benchmarked at 18.0 tCO_2/tH_2

4.2| Global Hydrogen Production Landscape

As of 2024, global hydrogen demand reached approximately 100 million tonnes (Mt), continuing a trend of steady growth. This market is overwhelmingly supplied by unabated fossil fuels, responsible for approximately 920 Mt of direct CO_2 emissions annually (International Energy Agency [IEA], 2025a).

The technology mix is dominated by two mature processes (IEA, 2025a):

a. **Steam Methane Reforming (SMR):** Using natural gas as a feedstock, SMR accounts for approximately two-thirds of all dedicated hydrogen production globally. It is the primary technology in regions with access to inexpensive natural gas, including the United States, Europe, and the Middle East.

b. **Coal Gasification:** This pathway contributes around 20% of the global supply and is the dominant technology in China, which alone accounts for 90% of the world's coal consumption for hydrogen production.

Low-emissions hydrogen (produced with either carbon capture or renewable electricity) represents less than 1% of total production (IEA, 2025a). The current operational landscape is therefore the carbon-intensive "likely baseline scenario" that new, cleaner technologies must outperform.

Table 14: Global Hydrogen Production by Top Countries (2023)

Country	Production Volume (Mtpa)	Primary Production Technology	Key End-Use Sectors	Source
China	~38	Coal Gasification (~60%), SMR (~30%)	Ammonia, Methanol, Refining	IEA (2025a)
United States	~10	SMR (dominant)	Refining, Ammonia	CRS Report R48196 (2024)
India	~6.5	SMR, Naphtha Reforming	Refining, Fertilisers	IEA (2024a)
Russia	~3	SMR	Refining, Ammonia, Methanol	IEA (2024a)
Canada	~3	SMR	Refining, Chemicals	IEA (2024a)
Germany	~2.2	SMR	Refining, Ammonia, Chemicals	European Hydrogen Observatory (2026)
Netherlands	~2.1 (demand)	SMR	Refining, Ammonia	European Hydrogen Observatory (2026)

Note: Figures are indicative and subject to annual variation and data source differences. China's figures represent approximately 38% of global production.

4.3| Defining "Best Performing Comparable Activities" (2020-2025)

To establish a credible and ambitious baseline for existing unabated technologies, it is necessary to identify the “best performing comparable activities” within the current operational fleet. The timeframe of 2020–2025 is selected to ensure the analysis is based on the most recent and relevant operational data.

This approach aligns with the established industrial principle of Best Available Technology (BAT). In the European Union, BAT is a cornerstone of the Industrial Emissions Directive (Directive 2010/75/EU; European Commission, 2010), operationalised through BAT Reference Documents (BREFs) that set performance standards for industrial installations (European Commission, 2023). The benchmark is therefore not based on the average performance of all facilities (which would be skewed by older, less efficient plants or more carbon-intensive pathways) but on the performance of the top percentile of the existing fleet, representing what is achievable with modern, well-operated equipment.

By setting the baseline at this high-performance level, it ensures that only significant improvements are recognised, thereby creating a meaningful standard for driving genuine decarbonisation and preventing the rewarding of marginal gains.

4.4| Analysis of Specific CO_2 Emissions from Comparable Hydrogen Plants

4.4.1| Methodological Framework

The analysis adheres to a structured benchmarking approach, focusing on the performance of existing, commercially mature technologies. The core principle is to establish a benchmark based on the performance of the Best Available Technology (BAT) currently deployed in the sector, as comprehensively analysed in Section 3 of this SI. This ensures the benchmark reflects a high standard of operational reality, not merely theoretical potential.

This report focuses specifically on direct emissions at the production facility. The rationale for this boundary choice is twofold: (a) direct emissions are the most reliably measured and verified, as they depend on facility-specific process parameters rather than value-chain assumptions; and (b) the deliberate exclusion of upstream emissions provides a structurally conservative baseline that yields fewer carbon credits than a full lifecycle baseline would.

4.4.2| Scope and Validity Period

The scope of this analysis is strictly limited to unabated hydrogen production from fossil fuels — i.e., facilities operating without any Carbon Capture, Utilisation, and Storage (CCUS) technology. The technologies covered are:

- Steam Methane Reforming (SMR)
- Coal Gasification

- Naphtha Reforming (primarily within refineries)

A separate benchmark is established for each distinct technology pathway. These benchmarks are proposed for a three-year validity period, aligned with the methodology's update cycle. At each crediting period renewal, the BAT benchmark should be formally updated in line with methodology requirements.

4.4.3| Benchmark Determination: Stepwise Approach

The benchmarks were established following a systematic, stepwise approach consistent with international best practices for industrial performance standards:

a. **Step 1: Delineation of the Sector and Definition of the Product.** The scope is defined as currently operating, commercially mature, unabated fossil-fuel-based hydrogen production technologies (SMR, Coal Gasification, Naphtha Reforming). The product is gaseous hydrogen. The performance metric is direct emissions at the facility gate, measured in tonnes of CO_2 per tonne of hydrogen (tCO_2/tH_2).

b. **Step 2: Data Collection and Identification of Top-Performing Facilities.** Operational data was gathered from multiple authoritative sources to identify the performance of best-in-class facilities. As a comprehensive, globally audited, facility-level database of every hydrogen plant's direct emissions is not publicly available, this analysis relies on a robust triangulation of data from: the International Energy Agency's Global Hydrogen Reviews (IEA, 2021, 2024a, 2025a); the U.S. Congressional Research Service analysis (CRS, 2024); the IEAGHG Techno-Economic Evaluation (IEAGHG, 2024); the Hydrogen Council Lifecycle Assessment (Hydrogen Council, 2021); the EU BREF for the Refining of Mineral Oil and Gas (European Commission, 2023); and peer-reviewed LCA studies (Patel et al., 2024; Capodaglio et al., 2024; Elgowainy et al., 2024; Al-Qahtani et al., 2021). The "top-performing" facilities are identified as those operating at the highest efficiency, corresponding to the Best Available Technology. As an independent cross-check on the SMR value, the EU Emissions Trading System publishes, under Commission Implementing Regulation (EU) 2021/447, the average performance of the 10% most efficient installations for related benchmarks; the ammonia benchmark of 1.604 tCO_2e/tNH_3 corresponds, through the stoichiometric hydrogen content of ammonia and after removing the ammonia-synthesis increment, to a standalone hydrogen figure of the order of 8.1–8.5 tCO_2/tH_2, consistent with the value adopted here. The 2021/447 vintage is retained deliberately: the subsequent 2026–2030 benchmark period incorporates electrolytic hydrogen into the relevant populations, which would no longer represent an unabated-fossil reference.

c. **Step 3: Calculation of the Benchmark Value.** The final benchmark for each pathway is set at the lower end of the BAT performance range identified in Step 2. This conservative selection ensures that only projects demonstrating performance superior to the best existing unabated plants generate carbon credits through the methodology.

4.5| Pathway BenchmArks

4.5.1| Pathway 1: Steam Methane Reforming (SMR) from Natural Gas

4.5.1.1 Benchmark Definition

Direct CO_2 emissions at the production facility, measured in tCO_2/tH_2. This includes both process CO_2 (from the water-gas shift reaction) and combustion CO_2 (from natural gas burned in the reformer furnace for process heat). Approximately one-third of total SMR CO_2 is generated via fuel combustion in the furnace flue gas; the remainder originates from the high-purity process stream (Ammoniaenergy.org, 2024; IEAGHG, 2024).

4.5.1.2 Data and Performance Analysis

Modern, efficient SMR plants represent the BAT for this pathway. The following authoritative data points triangulate the direct emissions range for BAT-level plants:

Source	Direct Emissions (tCO_2/tH_2)	Basis
IEA (2024a)	~9.0 (central estimate, "around 9 kg $CO_2e/kg\ H_2$")	Direct emissions; per CRS (2024) citing IEA GHR 2023
Capodaglio et al. (2024)	11.0 (average across reviewed LCA studies)	Includes some upstream; peer-reviewed review
Patel et al. (2024)	12.3–13.9 (LCA, pipeline NG vs. LNG)	Full cradle-to-gate LCA; peer-reviewed
IEAGHG (2024)	~8.9–9.5 (modern merchant SMR plant)	Direct emissions from techno-economic assessment
Al-Qahtani et al. (2021)	8.9 (harmonised direct, large-scale)	Peer-reviewed harmonised LCA
Elgowainy et al. (2024)	9.3 (US DOE GREET model)	Peer-reviewed, direct + immediate
Lewis et al. (2022)	8.5–9.5 (NETL comparison of commercial technologies)	DOE report, direct emissions only

4.5.1.3 Direct Emissions Benchmark:

The peer-reviewed and institutional evidence converges on a direct emissions range of 8.5–9.5 tCO_2/tH_2 for best-in-class, modern, large-scale SMR plants. . The lower bound of this range is adopted as the crediting benchmark; the single value applied by the methodology is 8.5 tCO_2/tH_2, not the range. Selecting the lower end of the BAT range for conservativeness, the unabated SMR benchmark is 8.5 tCO_2/tH_2. Selecting the lower end of the BAT range for conservativeness, Unabated SMR Benchmark: 8.5 tCO_2/tH_2

4.5.1.4 Separated Upstream Emissions Factor:

While not part of the direct emissions benchmark, the upstream emissions from the natural gas supply chain are significant. The IEA identifies that between 75% and 95% of total emissions from unabated NG-based hydrogen occur at the point of production (IEA, 2024a). The remaining 5–25% (approximately 0.5–3.0 $tCO_2\text{-eq}/tH_2$) originates from upstream extraction, processing, and transport — critically influenced by the methane leakage rate. The IEA identifies the BAT for upstream supply chains as having an emissions intensity of approximately 4.5 kg CO_2-eq/GJ of natural gas (IEA, 2021). By explicitly excluding these upstream emissions from the crediting baseline, the methodology ensures maximum conservativeness: the full lifecycle emissions of even the best SMR plants (10.8–12.9 tCO_2-eq/tH_2) are substantially higher than the credited baseline of 8.5 tCO_2/tH_2.

4.5.2| Pathway 2: Coal Gasification

4.5.2.1 Benchmark Definition:

The benchmark for this pathway is the direct CO_2 emissions at the production facility, measured in tCO_2/tH_2.

4.5.2.2 Data and Performance Analysis:

Coal gasification is inherently more carbon-intensive than SMR due to coal's higher carbon-to-hydrogen ratio. The following authoritative data points establish the range:

Source	Direct Emissions (tCO_2/tH_2)	Basis
IEA (2024a)	17.6–20.8 (derived: "22–26 total" × ">80% direct")	IEA GHR 2024 states >80% of total 22–26 is direct
IEA (2023a)	~20 ("around 20 $kgCO_2/kgH_2$" direct)	IEA Coal-Hydrogen report, direct emissions
CRS (2024)	17.6–20.8 (derived from IEA data)	Congressional Research Service analysis
Lewis et al. (2022)	18.1–19.2 (NETL assessment, commercial plants)	DOE report, direct emissions only
Hydrogen Council (2021)	11.6–25.3 (wide range, depends on coal type and plant design)	Lifecycle assessment; coal type is critical variable

The IEA's statement that "over 80% of the total lifecycle emissions from coal-based hydrogen (22–26 kg CO_2-eq/kg H_2) occur directly at the plant" yields a direct emission range of approximately 17.6–20.8 tCO_2/tH_2. The IEA Coal-Hydrogen report (IEA, 2023a) provides a central direct estimate of "around 20 $kgCO_2/kgH_2$". The NETL comparison of commercial technologies reports 18.1–19.2 tCO_2/tH_2 for US coal gasification (Lewis et al., 2022).

4.5.2.3 Direct Emissions Benchmark:

Selecting the lower end of the BAT range for conservativeness (representing the most efficient modern IGCC-based or entrained-flow gasification plants):

- **Unabated Coal Gasification Benchmark: 18.0 tCO_2/tH_2**
- *Note:* The benchmark is set at 18.0 tCO_2/tH_2 — a single, unambiguous value aligned with the IEA's central estimate and the lower end of the NETL range. This replaces the earlier draft value of 17.6, which was derived from the minimum of the "80% of 22"

calculation. 18.0 is better supported by the weight of evidence and is within the BAT performance range.

4.5.2.4 Separated Upstream Emissions Factor:

Coal mining and processing generate significant upstream emissions (fugitive methane from coal seams, transport emissions). The IEA reports that the best-performing coal supply chains (5th percentile) have an upstream emissions intensity of approximately 6.0 kg CO_2-eq/GJ of coal (IEA, 2021). For Chinese coal specifically, the Hydrogen Council (2021) notes that “uncontrolled coal-seam fires” contribute significantly higher upstream emissions. These are excluded from the crediting baseline, adding a further layer of conservativeness.

4.5.3| Pathway 3: Naphtha Reforming

4.5.3.1 Benchmark Definition:

Direct CO_2 emissions at the production facility, measured in tCO_2/tH_2. This pathway is almost exclusively found integrated within petroleum refineries, where naphtha catalytic reforming produces hydrogen as a co-product alongside high-octane reformate for gasoline blending.

4.5.3.2 Data and Performance Analysis:

Data on standalone naphtha reforming is less common, as it is typically part of a larger, integrated refinery complex. The IEA GHR 2024 notes that hydrogen from naphtha catalytic reforming can be treated as having 0 kg CO_2/kg H_2 emissions when classified as a by-product (with all emissions allocated to reformate), or up to 10 kg CO_2/kg H_2 when all emissions are allocated to hydrogen (IEA, 2024a). This allocation challenge is inherent in multi-product refinery processes. The available process-specific literature provides the following:

Source	Direct Emissions (tCO_2/tH_2)	Basis
Kudoh et al. (2017)	6.3 (calculated from 2.24 tCO_2/kL naphtha)	Peer-reviewed input-output LCA (Japan)
IEA (2024a)	0–10 (range depending on allocation method)	IEA GHR 2024, by-product allocation
EU BREF Refining (2023)	Not separately reported for H_2	Integrated refinery emissions

4.5.3.3 Direct Emissions Benchmark:

Based on the available process-specific peer-reviewed data and applying an energy-allocation method consistent with ISO 14044 (rather than by-product exemption):

- **Unabated Naphtha Reforming Benchmark: 6.3 tCO_2/tH_2**
- *Note on allocation method:* The 6.3 tCO_2/tH_2 value is derived from an energy-allocation approach in which emissions from the naphtha reforming process (including furnace firing) are allocated between hydrogen and reformate on the basis of their energy content (Kudoh et al., 2017). This approach is more conservative than the by-product exemption (0 $kgCO_2/kgH_2$) used by some

accounting frameworks, but less conservative than full allocation to hydrogen alone (~10 $kgCO_2/kgH_2$). Activity developers applying this benchmark shall disclose the allocation methodology used. Where the IEA by-product convention (0 $kgCO_2/kgH_2$) is applied by the host country's regulatory framework, the 6.3 tCO_2/tH_2 benchmark nevertheless represents the conservative default. A distinct question, separate from the emission value, is whether the displacement of hydrogen arising as a co-product of naphtha catalytic reforming should be credited at all: the output of that hydrogen is driven by gasoline demand rather than by hydrogen demand, so displacing it may not reduce its production.

4.5.3.4 Separated Upstream Emissions Factor:

The upstream emissions for naphtha are intrinsically linked to the complex operations of the oil refinery from which it is derived. These emissions are highly variable, depending on the specific refinery configuration and crude oil slate. A universally applicable upstream factor is not separately established for this pathway; emissions are accounted for within the refinery's overall emissions profile.

4.6 | Summary of Benchmarks

This section establishes the following direct emission benchmarks for current, unabated hydrogen production technologies, based on operational records and analysis of the Best Available Technology for each pathway. These benchmarks serve as the likely baseline scenario for the industry.

Table 15: Direct Emission Benchmarks for Unabated Hydrogen Production (BAT)

Technology Pathway	Feedstock	Primary Region of Application	Direct Emissions Benchmark (tCO_2/tH_2)	Upstream Emissions (Excluded from Crediting Baseline)	Sources
Steam Methane Reforming (SMR)	Natural Gas	Global (ex-China)	**8.5**	~0.5–3.0 tCO_2-eq/tH_2 (pipeline NG)	IEA (2024a); Lewis et al. (2022); IEAGHG (2024); Al-Qahtani et al. (2021)
Coal Gasification	Coal	China (dominant)	**18.0**	~4.8–7.2 tCO_2-eq/tH_2 (coal mining/transport)	IEA (2024a); IEA (2023a); Lewis et al. (2022)
Naphtha Reforming	Naphtha (Oil)	Global (Refineries)	**6.3**	Variable (refinery-dependent)	Kudoh et al. (2017); IEA (2024a)

These benchmarks reflect the direct emissions performance of each technology at the BAT level. For a complete environmental assessment, direct emissions should be considered alongside upstream emissions. However, for the purpose of the methodology's crediting baseline (Section 7, eq.1–2), only the direct emission benchmarks are applied — a deliberate conservativeness choice.

4.6.1 | Addressing Data Scarcity and Ensuring Benchmark Application

A primary challenge encountered during this analysis was the scarcity of publicly available, verified, plant-level CO_2 emissions data for newly commissioned, non-CCS hydrogen plants — particularly for the "top 10%" of fossil-based facilities. The benchmarks established in this report are derived from triangulation across globally authoritative institutional reports and peer-reviewed literature (as detailed in Section 5).

The following application rules are recommended:

a. **Prioritise Project-Level Assessment:** Whenever feasible, a project-specific assessment of direct emissions should be conducted for brownfield retrofits (Scenario B in the methodology, Section 7.3.3). Historical emissions data averaged over the most recent 3 years of continuous operation provides the most accurate representation of a given facility's performance.

b. **Use Benchmarks as a Mandatory Cap:** In cases where a developer is unable to establish a project-specific benchmark, or where such an assessment results in a higher (i.e., less stringent) emissions value, the benchmarks established in this section shall be applied as a mandatory cap. This is operationalised in the methodology through the equation: $EF_{baseline} = \min(EF_{hist}, EF_{BAT})$ (Section 7, eq.3).

c. **Default Application for Greenfield Activities:** For greenfield activities (Scenario A in the methodology, Section 7.3.2), the global BAT defaults above shall apply directly. The applicable default shall correspond to the dominant baseline technology pathway in the host country. Where the dominant baseline technology is not definitively established, the SMR BAT of 8.5 tCO_2/tH_2 shall apply as the conservative global default, as SMR yields the lowest direct emissions of the three fossil pathways.

d. **Consistency with Methodology:** The BAT values flow directly into the methodology's crediting baseline equations (Section 7, eq.1–2). The $\min(EF_{BAT,global}, EF_{BAT,national})$ logic in eq.1 ensures that if a host country has established a more stringent national BAT (i.e., lower than the global defaults above), the national value prevails.

4.6.2 | Reconciliation: Direct Emissions vs. Lifecycle Emissions

To ensure complete transparency, the following table reconciles the direct emission benchmarks used in the crediting baseline with the indicative full lifecycle (cradle-to-gate) emission intensities presented in Section 3 of this SI:

Table 16: Reconciliation of Direct vs. Lifecycle Emission Benchmarks

Technology	Direct Emissions BAT (tCO_2/tH_2) — Used in Crediting Baseline	Upstream Emissions (tCO_2-eq/tH_2) — Excluded	Indicative Full LCA (tCO_2-eq/tH_2) — Informational Only	Conservativeness Margin

SMR (NG)	**8.5**	2.3–3.9	10.8–12.4	~21–31% below LCA
Coal Gasification	**18.0**	4.0–8.0	22–26	~18–31% below LCA
Naphtha Reforming	**6.3**	Variable	6.3–10.0	Up to ~37% below full allocation

This reconciliation demonstrates that the crediting baseline is systematically conservative — set approximately 20–30% below the full lifecycle baseline for all pathways. This structural conservativeness, combined with the Downward Adjustment Factor (Section 7.4) and the conservative BAU check (Section 7.5–7.6), ensures that the methodology's issuable emission reductions substantially understate the true climate benefit, in full alignment with the GS4GG Principles and the Paris Agreement's environmental integrity requirements.

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5.| SECTION 5: COMMON PRACTICE ANALYSIS: GREEN HYDROGEN PRODUCTION FACILITIES (2025-2030)

This section provides an evidence-based assessment of whether green hydrogen production technology has achieved, or will achieve, “common practice” status globally within the 2026–2030 timeframe. The analysis is conducted in strict accordance with the CDM common practice methodology (Tool 24, Version 3.1; UNFCCC, 2012), which provides a quantitative framework for evaluating technology diffusion and market saturation.

Conclusion: Based on the quantitative analysis presented below, green hydrogen production is unequivocally **not common practice in 2026** and is **highly unlikely to achieve this status by 2030**. The technology’s negligible market share (<1% of global hydrogen production) and its substantial and persistent cost premium over conventional grey hydrogen (60–400% depending on region) mean it decisively fails the required tests. This economic disparity classifies green hydrogen as a “different technology” under the CDM framework — one that is not commercially viable without significant financial support. The path to 2030 is characterised by a structural deadlock between policy ambition, investment commitment, and secured demand, which will prevent green hydrogen from becoming a standard technology choice within the forecast period.

5.1 | Detailed Explanation of Common Practice Test

The GS4GG Methodology Tool: Common Practice Analysis (MT400-06) is the instrument applied by this methodology at Section 6.5. It employs a quantitative test to ensure a consistent and replicable evaluation. The construction of that test follows the established CDM Tool 24 (Version 3.1) F-factor approach, which MT400-06 adopts; the description below is given in those terms, and the governing threshold is that of MT400-06. Technology is "common practice" only if it meets two conditions:

1. **Factor F > 0.2:** F = 1 - (Ndiff / Nall), where 'Nall' is the total number of similar non-CDM projects, and 'Ndiff' is the number of those projects using "different technologies". Under the CDM Tool 24 formulation a factor F below 0.2 indicates that the technology has not achieved significant market penetration. Under MT400-06, as invoked by this methodology, the threshold is stricter: the technology is not common practice where the market penetration factor F remains below 5%. Green hydrogen falls below both thresholds by a wide margin, so the classification is unaffected by which is applied; the governing threshold for this methodology is the MT400-06 figure.

2. **(Nall - Ndiff) > 3:** The number of similar projects using non-different technologies must exceed three. This condition ensures that a technology cannot be considered common practice based on a very small number of installations, even if they represent a high proportion of a tiny market.

5.2| Key Definitions:

a. **Similar Projects:** Located in the applicable geographical area, apply the same "measure" (e.g., technology switch), use the same energy source/fuel/feedstock (if a technology switch), produce comparable goods/services, have capacity within +/-50% of the proposed project, and commenced commercial operation before a specified date.

b. **Different Technologies:** Technologies are "different" if they vary by energy source/fuel, feedstock, installation size, investment climate factors (e.g., access to technology, subsidies), or if their unit cost of capacity or output differs by at least 20%. This economic criterion is vital, as it allows for green hydrogen to be considered "different" if it's significantly more expensive or lacks policy support.

c. **Critical Economic Criterion:** This criterion explicitly states that a technology is to be considered "different" if its unit cost of output differs from the conventional alternative by at least 20%. As will be detailed extensively in in this report, the levelized cost of producing green hydrogen is currently multiple times higher than that of grey hydrogen, placing it far beyond this 20% threshold. This profound economic disparity is the central pillar of the assessment, cementing green hydrogen's status as a "different technology." It is not a simple, interchangeable substitute for grey hydrogen but rather a premium product that cannot compete on a level economic playing field without substantial external financial intervention.

5.3| Current Landscape of Global Hydrogen Production (2026)

To apply the common practice framework, it is essential to first establish a baseline understanding of the global hydrogen market as it stands in 2025. This landscape is characterized by the overwhelming dominance of conventional, fossil-fuel-based production, with low-emissions hydrogen occupying a marginal and nascent position.

5.3.1| Total Global Hydrogen Production

Global hydrogen demand reached approximately 100 million tonnes (Mt) in 2024, up 2% from 2023 (International Energy Agency [IEA], 2025a). This market is almost entirely supplied by conventional hydrogen from unabated fossil fuels — primarily grey hydrogen from natural gas (~62% of dedicated production) and brown/black hydrogen from coal (~20%), with the remainder from oil/naphtha reforming and by-product streams.

Low-emissions hydrogen production (both green and blue) grew by 10% in 2024 and reached approximately 0.9 Mt, on track to reach 1 Mt in 2025 — but this still accounts for **less than 1% of total global production** (IEA, 2025a). The Hydrogen Council reports that of the approximately 895 kt/yr of operational clean hydrogen capacity globally, only ~185 kt/yr is renewable hydrogen (i.e., from electrolysis powered by renewables), with the remainder being low-carbon hydrogen primarily from fossil fuels with CCS in North America (Hydrogen Council, 2024)..

5.3.2| Operational Green Hydrogen Capacity

Global installed water electrolyser capacity reached **2 GW by the end of 2024** (IEA, 2025a) — significantly below the 5 GW that had been projected in IEA GHR 2024. An additional 1+ GW was commissioned through mid-2025, with China accounting for approximately 65% of global installed capacity (IEA, 2025a). The commissioning of the 500 MW Envision Chifeng project in Inner Mongolia in July 2025 represented a landmark — the world's first half-GW-scale operational electrolyser project.

There is a critical distinction between nameplate electrolyser capacity (GW) and actual hydrogen produced (tonnes). An electrolyser's annual output is a function of its capacity factor, which depends on the availability and cost of renewable electricity. An electrolyser coupled to intermittent solar or wind has a capacity factor of 20–45%, meaning its annual hydrogen output is substantially less than its nameplate rating implies. Therefore, focusing solely on GW growth overstates the market penetration of green hydrogen in tonnage terms.

Green hydrogen production is highly concentrated geographically. As of mid-2025, operational green hydrogen production of any significant scale (>10 MW) exists in fewer than ten countries, with China hosting approximately 65–80% of global operational electrolyser capacity (IEA, 2025a; Hydrogen Council, 2024).

5.3.3| Initial Common Practice Assessment (2026)

Applying the CDM Tool 24 criteria to the 2026 baseline:

a. Absolute threshold: The number of distinct operational green hydrogen facilities globally exceeds the minimum requirement of three. The condition (Nall − Ndiff) > 3 is met.
b. Market diffusion test: Green hydrogen facilities represent a tiny fraction of the total number of hydrogen production plants worldwide. With green hydrogen's market share at approximately 0.2% of total global hydrogen production (by volume), the value of Ndiff is extremely large relative to Nall, and Factor F is far below the 0.2 threshold.
c. Economic criterion: The prohibitive cost premium firmly establishes green hydrogen as a "different technology" (see Section 5 below).

Assessment: Green hydrogen is unequivocally not common practice in 2026.

5.4| Projected Growth and Market Penetration (2025-2030)

While the 2026 baseline is clear, the common practice assessment requires a forward-looking analysis to 2030. This involves scrutinizing the vast pipeline of announced projects and distinguishing between aspirational targets and the more sober reality of projects likely to become operational. This analysis reveals a market facing significant headwinds, characterized by a stark divergence between green and blue hydrogen project maturity and a structural deadlock among policymakers, investors, and offtakers.

5.4.1| Project Pipeline: Ambition vs. Reality

The announced project pipeline for low-emissions hydrogen has undergone significant downward revision. The IEA Global Hydrogen Review 2025 reports (IEA, 2025a):

a. **Total pipeline:** Low-emissions hydrogen could reach **37 Mtpa by 2030** — a significant reduction from the 49 Mtpa estimated in GHR 2024 and the aspirational 65 Mtpa originally envisaged. Cancellations and delays drove this reduction.

b. **FID share:** Approximately **9% of announced projects** have secured committed investments (up from 4% in GHR 2024). While the number of FIDs grew by ~20% in 2024, this still represents a small fraction of the total pipeline.

c. **Operational or FID-approved projects** could deliver approximately **4.2 Mtpa by 2030** — roughly a fivefold increase from 2024 levels but still only ~4% of total projected hydrogen demand (IEA, 2025a).

The Hydrogen Council estimates a feasible clean hydrogen production level of approximately 12 Mtpa by 2030 (Hydrogen Council, 2024). Bloomberg NEF's revised projections suggest 16 Mtpa of total clean hydrogen (both green and blue) by 2030 (BNEF, as cited in Clifford Chance, 2025).

5.4.2| Project Maturity and Offtake-Gap:

A critical dynamic is the higher commercial maturity of blue hydrogen projects compared with green. Blue hydrogen projects historically showed an FID rate approximately three times that of green hydrogen (IEA, 2024a). However, no new blue hydrogen projects commenced production in 2024 (IEA, 2025a), suggesting that even the blue pathway faces deployment challenges.

The market is caught in a structural deadlock: governments announce ambitious targets, but investors are hesitant to commit capital without guaranteed buyers (offtakers). This "offtake gap" is a primary bottleneck — **only 12% of planned 2030 green hydrogen production has secured a buyer** (International Renewable Energy Agency [IRENA], 2024b). This prevents financing, which in turn prevents the scaling needed to reduce costs.

Table 17: Global Clean Hydrogen Projections to 2030 (Announced vs. Realistic Scenarios) [6]

Metric	Announced Pipeline (Mtpa)	Realistic/FID-Based Projection (Mtpa)	Source

[6] Hydrogen production – Global Hydrogen Review 2024, IEA accessed June 30, 2025.

Green Hydrogen	~25–30 (from announced electrolysis)	3–5 (operational + FID-approved)	IEA (2025a)
Blue Hydrogen	~7–12 (from announced CCUS projects)	1–3	IEA (2025a)
Total Clean Hydrogen	~37 (revised down from 49)	4.2 (operational/FID) to 12–16 (optimistic)	IEA (2025a); Hydrogen Council (2024)

Note: “Realistic” figures represent operational and FID-approved projects. The broader range (12–16 Mtpa) reflects optimistic scenarios from the Hydrogen Council and BNEF that assume a significant acceleration of FIDs.

5.5| Economic Viability: “Different Technology” Test

The economic disparity between green and conventional hydrogen is the primary reason it must be classified as a "different technology."

5.5.1| Comparative Production Costs (2025-2026)

The cost hierarchy across hydrogen production pathways is clear and well-documented:

Hydrogen Type	Current LCOH (USD/kg)	Source
Grey Hydrogen (SMR)	$1.00–$2.50	IEA (2025a); Curico (2025)
Blue Hydrogen (SMR/ATR + CCS)	$2.00–$4.00	IEA (2025a); Curico (2025)
Green Hydrogen (Western markets)	$4.00–$8.00	IEA (2025a)
Green Hydrogen (China)	$2.50–$5.00	IEA (2025a)

Sources: Curico, E. (2025); IEA (2025a); Glenk & Reichelstein (2022).

5.5.2| Applying the 20% Economic Criterion

The CDM Tool 24 classifies a technology as “different” if its unit cost of output varies by at least 20% from the conventional alternative. Applying this criterion:

- **Most conservative comparison** (high grey vs. low green): $2.50/kg (grey) vs. $4.00/kg (green, China) = **60% premium**
- **Typical global comparison** (midpoint grey vs. midpoint green Western): $1.75/kg (grey) vs. $6.00/kg (green) = **243% premium**
- **Extreme comparison** (low grey vs. high green): $1.00/kg (grey) vs. $8.00/kg (green) = **700% premium**
- **In all credible scenarios, the cost premium for green hydrogen vastly exceeds the 20% threshold** — by a factor of 3 to 35. This is not a marginal or temporary difference; it is a fundamental economic barrier that prevents green hydrogen from competing with grey hydrogen on a purely commercial basis. This finding unequivocally classifies green hydrogen as a **“different technology”** under the CDM framework.

- The levelised cost and market-penetration figures applied in this assessment are the single dataset stated in this Section; where Sections 1 and 3 refer to cost premium or penetration, they cross-reference this Section rather than restating independent figures. This ensures that the common-practice conclusion rests on one internally consistent datase

5.5.3| Cost Reduction Trajectories to 2030

While optimistic forecasts once projected cost parity by 2030, more recent analyses reflect slower-than-expected deployment and persistent inflation. The IEA GHR 2025 explicitly notes: “cost projections for electrolysers being less optimistic than in previous years due to the limited deployment achieved to date” and “the increase in the cost of electrolysers due to inflation and slower-than-expected deployment of the technology has led to a larger cost gap with production from unabated fossil fuels” (IEA, 2025a). Modelling by Agora Energiewende and Guidehouse (2021) indicates that a carbon price of €100–€300/tCO_2 would be required for green hydrogen to achieve price parity with grey hydrogen — far exceeding current carbon prices in most jurisdictions..

Table 18: Comparative Levelized Cost of Hydrogen (LCOH) - 2025 & Projected 2030 ($/kg)

Hydrogen Type	LCOH 2025–2026 $(/kg)\vert$ $\backslash ProjectedLCOH2030 - Optimistic$(/kg)	Projected LCOH 2030 — Pessimistic ($/kg)	Key Cost Drivers	
Grey Hydrogen	$1.00–$2.50	$1.00–$2.50	$1.00–$2.50	Natural gas price
Blue Hydrogen	$2.00–$4.00	$1.50–$3.50	$2.00–$4.50	NG price, CCUS CAPEX
Green Hydrogen (Western)	$4.00–$8.00	$2.50–$4.00	$3.50–$6.00	RE electricity, electrolyser CAPEX
Green Hydrogen (China)	$2.50–$5.00	$1.50–$3.00	$2.00–$4.00	Lower RE/electrolyser costs

Sources: Curico (2025); IEA (2025a); Glenk & Reichelstein (2022); Agora Energiewende & Guidehouse (2021).

Even under the optimistic 2030 scenario, the minimum green hydrogen cost ($1.50/kg in China, $2.50/kg in Western markets) exceeds the grey hydrogen ceiling ($2.50/kg) by 0–60%. In most regions, the cost premium will remain well above the 20% threshold through 2030. It is therefore highly improbable that the cost gap will narrow to within the 20% threshold by 2030 across the majority of the global market.

5.5.4| Decisive Role of Policy and Carbon Revenue

The green hydrogen market is almost entirely a construct of public policy, not free-market forces. Its viability hinges on government interventions, confirming its non-common practice status.

5.5.4.1 Carbon Price and Subsidy

For green hydrogen to compete, a substantial carbon price—estimated at €100 to €300 per tonne of CO_2—would be required, far exceeding current levels. [7] In its absence, the market is dependent on direct subsidies. Key policies like the US Inflation Reduction Act (IRA) and the EU Hydrogen Bank are essential for project viability, with one analysis indicating that 70% of announced projects require such support to be profitable. [8]

5.5.5| Market Barriers and Investment Risks

Beyond cost, deployment is hindered by regulatory uncertainty, the critical offtake gap, infrastructure deficits for transport and storage, and water stress in many regions where projects are planned.[5]

Table 19: Key Global Policy Mechanisms and Support Levels for Clean Hydrogen

Region/ Country	Policy/Programme	Mechanism	Support Level	Status (as of mid-2026)
USA	IRA Section 45V	Production Tax Credit	Up to \$3.00/kg	**Curtailed:** P.L. 119-21 (signed July 4, 2025) requires construction to begin before Jan 1, 2028 — shortened from original 2033 deadline
EU	European Hydrogen Bank	Competitive Auction (Fixed Premium)	First auction: up to €4.50/kg; second auction: €1.2B	Active; RED III mandates 42% RFNBO for industrial H_2 by 2030
UK	Low Carbon H_2 Business Model	Contract for Difference (CfD)	Long-term price certainty	Active
Japan	CfD Mechanism	Price Support (CfD)	Covers gap for 15 years	Active

[7] Agora Energiewende and Guidehouse (2021): Making renewable hydrogen cost-competitive: Policy instruments for supporting green H_2

[8] Hydrogen production – Global Hydrogen Review 2024, IEA accessed June 30, 2025.

China	Industrial Policy	Provincial mandates, subsidies	Varies by province	Active; ~60% of global electrolyser manufacturing
India	National Hydrogen Mission	Subsidies, targets	5 Mtpa green H_2 by 2030	Active
Australia	Hydrogen Headstart	Production credits	$2/kg AUD refundable offset	Active

Note: The curtailment of the US IRA 45V credit — the most generous global hydrogen subsidy — by Public Law 119-21 (signed July 4, 2025) underscores the policy risk facing the sector. This development strengthens the case for carbon finance as a complementary, more stable revenue source.

5.5.5.1 Market Barriers

Beyond cost, deployment is hindered by: regulatory uncertainty (as demonstrated by the US 45V curtailment); the critical offtake gap (only 12% of planned 2030 production has a secured buyer; IRENA, 2024b); infrastructure deficits for hydrogen transport and storage; and water stress concerns in many high-potential regions. Capital spending on low-emissions hydrogen reached USD 4.3 billion in 2024 (an 80% increase year-on-year), with projections rising to ~USD 8 billion in 2025 (IEA, 2025a) — but this remains small relative to the estimated USD 200+ billion conventional hydrogen market.

Final Common Practice Assessment (2026-2030)

The cumulative evidence — spanning market penetration, project maturity, economic viability, and policy dependence — leads to a definitive conclusion:

1.1 | Quantitative Assessment

a. Market Penetration:

Even under the most optimistic growth scenario (16 Mtpa total clean hydrogen by 2030), green hydrogen — comprising only a fraction of total clean hydrogen — would represent approximately 3–5% of a growing total hydrogen market (~100–110 Mt by 2030). The Factor F will remain **well below the 0.2 threshold** required for common practice.

b. Economic Criterion:

The LCOH for green hydrogen is highly unlikely to fall within the 20% premium threshold of grey hydrogen by 2030 across the majority of the global market. Green hydrogen will therefore continue to be classified as a **"different technology"** under the CDM framework.

c. Absolute Threshold:

The number of operational facilities will continue to exceed the (N_all − N_diff) > 3 requirement. This condition alone is insufficient for common practice status.

1.2 | Classification

Green hydrogen production is classified as a **nascent technology** under the following criteria: - Market penetration: <1% of total global hydrogen production (2024–2025) - Cost premium: 60–400% over conventional grey hydrogen (vastly exceeding the 20% "different technology" threshold) - Geographical concentration: ~65% of operational capacity in a single country (China) - Project maturity: Only 9% of announced pipeline at FID - Policy dependence: Non-viable without subsidies, tax credits, or carbon revenue in nearly all markets

1.3 | Methodology-Level Exemption

Given the overwhelming evidence confirming that green hydrogen production is highly unlikely to become common practice globally by 2030, the following methodology-level exemption is established in accordance with the GS4GG Additionality Standard:

- Any green hydrogen activity submitted for validation under this methodology within three (3) years of the publication date of this methodology version shall automatically be deemed to satisfy the Common Practice Analysis requirement and is exempt from conducting an activity-level common practice calculation.
- For activities submitted after this 3-year validity period expires, the developer shall conduct an activity-level assessment following the GS4GG Methodology Tool: Common Practice Analysis (MT400-06), demonstrating that the market penetration share of green hydrogen in the applicable geographical area remains below the strict threshold (i.e., F < 5%) defined by the prevailing GS4GG standard.
- Trigger for re-evaluation: If, at any point during the 3-year exemption period, any of the following conditions are met, the exemption shall be formally reviewed: - Global renewable hydrogen production exceeds 2% of total hydrogen production (currently ~0.2%) - The LCOH for green hydrogen falls to within 30% of grey hydrogen LCOH in any major market without subsidy - A major economy (US, EU, China, India) mandates green hydrogen production as a legal requirement for industrial hydrogen consumers.

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6.| SECTION 6 RENEWABLE ELECTRICITY ATTRIBUTION AND RESOURCE-COMPETITION LEAKAGE

6.1 | Resource-competition question

Electrolytic hydrogen production is electricity-intensive. At the specific energy consumption adopted in Section 3 of approximately 50 MWh per tonne of hydrogen (inclusive of compression), and a steam-methane-reforming baseline of 8.5 tCO_2/tH_2, the activity is credited with approximately 0.17 tonnes of carbon dioxide for each megawatt-hour of renewable electricity it consumes.

The same megawatt-hour, had it instead been delivered to the electricity grid, would have displaced marginal fossil generation. On most of the grids where these activities will be sited, that displacement is worth between 0.5 and 0.9 tCO_2 per megawatt-hour; for the Indian grid, of the order of 0.71. The abatement credited to the activity is therefore smaller, per unit of electricity, than the abatement that the same electricity would have delivered to the grid — by a factor of three to four.

NOTE — GRID EMISSION FACTORS ARE ILLUSTRATIVE. The grid emission factors and the resulting figures in this subsection (0.5–0.9 tCO_2/MWh; the Indian value of ~0.71; the ~0.17 tCO_2/MWh break-even) are stated for demonstration only, to convey the order of magnitude of the resource-competition question. They are not normative defaults. The grid emission factor applied to any activity is the value determined under the methodology for that activity's grid and monitoring period, which varies by location and over time and will generally fall as grids decarbonise. Nothing in this section fixes a grid emission factor; the numbers here illustrate the mechanism, and the methodology's own provisions govern the value used.

It follows that the net mitigation of the activity depends entirely on a single question: would the renewable generating capacity supplying the activity have been built regardless? If it would — if the activity has drawn its electricity from capacity that was going to exist and serve the grid in any case — then the activity has diverted that electricity, the grid has replaced it with fossil generation, and the real mitigation is much smaller than 8.5 tCO_2/tH_2, and may be negative. If it would not — if the capacity exists only because the activity created the demand for it — then no grid displacement is forgone and the credited figure is real.

These two cases are described in the literature as the “compete” and “non-compete” interpretations of additionality (Ricks et al., 2023; Zeyen et al., 2024). The break-even is precise: the activity is unambiguously beneficial regardless of which case applies only where the host-grid emission factor is below approximately 0.17 tCO_2/MWh — the credited abatement per megawatt-hour consumed. Very few of the grids on which these activities will be built are that clean. On any higher-carbon grid, the integrity of the credit depends on the renewable generation being additional in effect, and not merely additional on paper.

6.2| Methodology assumption

It would be convenient to resolve the question of section 6.1 by assuming the favourable case — that the renewable capacity would not have been built but for the activity, so that no displacement is forgone. This methodology does not do so, for two reasons.

First, the assumption is a modelling artefact, not an established fact. The conflicting results in the literature turn on when the electricity system is permitted to reach its optimal generation mix. Where hydrogen demand is co-optimised with system expansion — so that the electrolyser competes with all other demand for new renewable capacity — electrolytic hydrogen is found to increase long-run system emissions by consuming high-quality renewable resources (Ricks et al., 2023). Where the system is instead permitted to expand to its optimum before the hydrogen load is introduced, the competition does not arise by construction (Zeyen et al., 2024). The favourable case is the second; it holds only in a world in which renewable deployment has already reached its optimal level, which is not the world these activities operate in.

Second, the real-world evidence points the other way. Renewable deployment at present is constrained principally by grid interconnection and permitting, not by demand: the International Energy Agency reports of the order of 1,650 GW of solar, wind and hydropower capacity in advanced development and awaiting grid connection as of mid-2024 (IEA, 2024b), and interconnection queues have continued to lengthen since. Where capacity is queue-constrained and demand-abundant, renewable generation contracted for an electrolyser is, in the ordinary case, generation that the grid would otherwise have taken — the compete case. Consistent with this, energy-system modelling for the European system finds that under annual or monthly matching a baseload electrolyser draws fossil-fuelled generation from the grid during deficit hours, producing higher emissions than would have occurred without the hydrogen demand at all (Zeyen et al., 2024).

Assuming the non-compete case would therefore be both unsupported and, on a high-carbon grid, most likely wrong. The methodology's integrity does not rest on it.

6.3| Integrity mechanism

What secures the credit is not an assumption about the counterfactual but the set of conditions the methodology imposes on the electricity supply. Taken together, these conditions constrain the activity to a consequential-emissions outcome no worse than that of an electrolyser supplied exclusively by its own dedicated, behind-the-meter renewable generation — the cleanest counterfactual physically available to electrolytic hydrogen. Ricks et al. (2023) establish this equivalence directly: a requirement of hourly matching, combined with deliverability and additionality, ensures a consequential-emissions outcome no worse than hydrogen produced exclusively from behind-the-meter carbon-free resources.

Each condition closes a specific failure mode:

Applicability condition	Methodology	Failure mode it closes

Dedicated, additional renewable generation	§3.2.5(b)(i)	Prevents the activity being supplied by re-allocation of existing generation; requires the capacity to be new.
Hourly temporal matching	§3.2.5(b)(iii); PD-1	Requires consumption to coincide with the activity's own renewable generation hour by hour, preventing the electrolyser from drawing fossil-backfilled grid electricity during hours when its renewables are not generating.
Geographic deliverability	§3.2.6	Requires the renewable generation to be physically deliverable to the activity, so that matching reflects real electricity flows rather than unbundled attributes.
Unmatched hours charged at the grid emission factor	§8.3; PD-1	Any hour of consumption not matched to the activity's renewable generation is charged at the grid emission factor, so the accounting penalises the precise failure mode rather than assuming it away.

The mechanism is supported by a substantial and, in places, contested modelling literature. This section sets out both sides of that literature and explains why the methodology adopts the conservative reading.

6.3.1| Evidence that hourly matching secures the outcome

United States (Ricks et al., 2023). Hourly matching with deliverability and additionality is identified as the best practical means of minimising the real emissions impact of grid-connected hydrogen, and is shown to deliver a consequential outcome no worse than behind-the-meter supply. Annual matching, by contrast, is found to produce emission intensities higher than those of conventional (grey) hydrogen.

India (TransitionZero, 2026). Modelling of the Indian steel sector's use of green hydrogen and 24/7 carbon-free electricity finds that hourly matching cuts the sector's emissions intensity below the level achieved by full annual matching — in the India West region, from 0.85 to 0.47 tCO_2 per tonne of crude steel — because hour-by-hour matching guarantees real abatement rather than annual-average credits. The same study finds hourly matching 16% cheaper to the power system than 100% annual matching, and hourly-matched green hydrogen produced at approximately USD 3.7/kg. Although modelled for Indian steel, the electricity-matching findings generalise to green hydrogen production wherever the electrolyser draws on a shared grid.

Europe (Zeyen et al., 2024). Local additionality is found necessary to guarantee low emissions, with the largest emission reduction achieved under hourly matching where surplus generation can be exported. Under annual matching, a baseload electrolyser is shown to draw fossil generation during deficit hours, producing higher emissions than no hydrogen demand at all.

6.3.2| Evidence that qualifies the case for strict hourly matching

A second line of work finds the advantage of hourly over looser matching to be smaller, or to disappear, under particular conditions — principally where the electrolyser operates flexibly, where cheap hydrogen storage is available, or where the background grid is already substantially decarbonised. The methodology does not dismiss this work; it is the reason the section's claim is bounded rather than absolute.

Giovanniello et al. (2024), Nature Energy. The central finding is that the conflicting results in the literature are driven by the additionality assumption: substantially lower consequential emissions are achievable under annual matching when one presumes that renewables for non-hydrogen demand do not compete with those contracted for hydrogen. The authors argue that the competing interpretation likely overestimates the emissions impact of annual matching and underestimates that of hourly matching, and they support beginning with annual matching in near-term contexts that resemble the non-compete case. This is the most directly dissenting source, and it is cited here for that reason.

Ruhnau and Schiele (2023), Energy Policy. Using historical marginal emission factors for the German grid, the authors find that hourly matching oversizes wind–electrolysis components and raises costs, that annual matching can slightly reduce system emissions through optimised electrolyser operation, and they recommend an annual additionality criterion without a strict hourly requirement. Zeyen et al. (2024) contest this on the grounds that it relies on historical marginal factors and a narrow technology set; the disagreement is methodological and unresolved.

Namazifard et al. (2025) and related work. Comparative EU modelling similarly finds that relaxing strict simultaneity reduces production costs, particularly where storage is expensive, and that the emissions penalty of doing so is modest under some system conditions. Zeyen et al. (2024) themselves identify scenarios — largely decarbonised grids, or flexible electrolysis — in which annual matching reduces emissions.

6.3.3| Methodology adoption

The dispute is genuine and turns on an assumption that cannot be verified for an individual activity: whether the renewables contracted for hydrogen compete with renewables for other demand. The dissenting work is largely correct on its own terms — where the non-compete case holds, or the grid is already clean, or the electrolyser is flexible, looser matching performs acceptably. But those are precisely the conditions the methodology cannot guarantee for every activity across every host grid and crediting period.

The methodology resolves the dispute by refusing to depend on its outcome. Where the favourable (non-compete) case holds, hourly matching costs a little more than necessary and loses nothing in integrity. Where the unfavourable (compete) case holds — the ordinary case on a queue-constrained, high-carbon grid — hourly matching is what prevents over-crediting, and looser matching would permit it. Adopting hourly matching, with a grid-emission-factor charge on any unmatched hour, is therefore correct under both readings of the disputed assumption: it is never worse than necessary, and it is decisive exactly where the risk is real. This is the same logic by which Giovanniello et al. (2024) themselves note that the compete interpretation is the appropriate default wherever the non-compete conditions cannot be assured.

The three jurisdictions in which hourly matching is found to secure the outcome — the United States, India and Europe — and the dissenting work that qualifies it, together support the same operational conclusion for a conservative crediting methodology: hourly matching, backed by a grid-emission-factor charge on unmatched hours, secures the integrity of the credit without relying on any assumption the methodology cannot enforce.

6.4 | Bounded Claim

The equivalence established in §6.3 is not a claim that resource-competition leakage is zero. Ricks et al. (2023) are explicit that even behind-the-meter generation competes for the best renewable resource sites and can influence system-level emissions, positively or negatively, by exporting surplus. The correct statement of the methodology's position is therefore bounded, and is stated here so that it is not over-read:

Under hourly matching with deliverability and additionality, the activity's consequential emissions are no worse than those of an electrolyser supplied exclusively by its own behind-the-meter renewable generation — which is the minimum achievable for any electrolytic hydrogen production drawing on a shared electricity system. A small residual competition for renewable resource sites may remain; it is bounded by this equivalence, and it is not reducible further by any accounting treatment available to the methodology.

This is the honest limit of the claim, and it is sufficient. The methodology does not need to demonstrate zero leakage; it needs to demonstrate that the credited activity performs at least as well as the cleanest counterfactual and that the conditions securing this are enforced. Both are established.

6.5 | Market-substitution leakage

A distinct question from competition for renewable electricity is whether the conventional hydrogen displaced by the activity continues to be produced and to serve other markets — in which case the displacement credited to the activity would be offset by continued fossil production elsewhere. The methodology's treatment distinguishes two cases.

Brownfield activities. Where the activity replaces on-site fossil hydrogen production and §3.2.10 requires the physical decommissioning of the displaced equipment, the displaced production capacity is removed and cannot continue to serve other markets. Market-substitution leakage cannot arise in this case, and its exclusion is sound. The decommissioning requirement is what makes the exclusion defensible, and the two provisions are to be read together.

Greenfield activities supplying existing consumers. Where the activity is greenfield and supplies a consumer previously served by a third-party fossil-hydrogen producer, that producer may continue to operate and to serve other customers. In this case the exclusion is not automatically justified. Consistent with PD-8 (Option B), the methodology requires an assessment of whether the incumbent fossil supplier continues in operation, and a leakage deduction where it demonstrably does. This confines the exclusion to the circumstances in which it is physically warranted, rather than asserting it generally.

The consultation draft excluded market-substitution leakage generally, in a footnote, on the assumption that growing global hydrogen demand would absorb green hydrogen as a substitute rather than a displacement. That assumption is not relied upon here; the exclusion is instead tied to the physical fact of decommissioning for brownfield activities and to an evidenced assessment for greenfield ones.

6.6 | Summary of the integrity basis

The treatment of renewable-electricity competition under this methodology rests on the following chain, none of which depends on an unsupported assumption about the counterfactual:

The net mitigation of an electrolytic hydrogen activity depends on whether its renewable electricity is additional in effect (Section 6.1). The methodology does not assume this; the energy-system evidence would not support the assumption on a high-carbon grid (Section 6.2). Instead, the applicability conditions — dedicated additional renewables, hourly matching, deliverability, and a grid-emission-factor charge on unmatched hours — constrain the activity to a consequential outcome no worse than dedicated behind-the-meter supply, an equivalence established across US, Indian and European modelling (Section 6.3). The claim is bounded to that equivalence and stated as such (Section 6.4). Market-substitution leakage is excluded only where physical decommissioning removes the displaced capacity, and is assessed and deducted otherwise (§6.5).

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7.| SECTION 7 — DERIVATION OF DEFAULT VALUES

7.1 | Summary of defaults

#	Default	Value applied	Direction of error
1	GWP for hydrogen	14.4 (GWP_{100})	Conservative (upper bound)
2	Fugitive hydrogen leakage default	2% of H_2 produced	Conservative (above measured range)
3	Mass-balance uncertainty trigger	±20%	Conservative (triggers the default)
4	Grid transmission & distribution losses (TDL)	0.10 (10%)	Conservative (upper bound)
5	Transport de-minimis distance	200 km (two-way)	Immaterial at threshold
6	Renewable allocation threshold	≥70% of net generation	Neutral / integrity
7	Renewable COD window	36 months	Integrity (additionality link)
8	Potable-water cap	5% (two-limb)	Conservative (safeguard)
9	Grid electricity cap and triggers	10%; 15% / three-in-five	Conservative (integrity)
10	Embodied-emissions basis	EPD or IPCC/IEA median	Conservative (full inclusion)

7.2| Global Warming Potential for hydrogen

Value applied: 14.4 (GWP_{100})

Source. Sand et al. (2023), a multi-model assessment of the indirect GWP of hydrogen, as applied in the methodology parameter table (GHM 5).

Derivation. Sand et al. report a model-mean GWP_{100} for hydrogen of 11.6 ± 2.8 (one standard deviation). The methodology applies 14.4, the upper bound of that range, as a deliberate conservativeness adjustment to the central estimate. AR5 — the declared GWP set for this methodology — does not itself report a value for hydrogen, so the value is sourced independently from Sand et al. The full derivation, including the reconciliation with the declared GWP set, is given in Section 4 and is not repeated here.

Direction of error. Conservative. Using the +1σ upper bound rather than the central estimate increases the fugitive-emission deduction and reduces net credits.

7.3 | Fugitive hydrogen leakage default

Value applied: 2% of hydrogen produced

Source. Applied where mass-balance reconciliation uncertainty exceeds ±20% (§7.3). Measured leakage estimates from the electrolysis literature: 0.2% for steady-state membrane crossover (Arrigoni & Bravo Diaz, JRC); a literature-synthesis average of 1.72% across all operational losses (Trapani et al., 2025); the Sand et al. (2023) and Wiltshire et al. (2025) syntheses inform the atmospheric treatment.

Derivation. The measured production-stage leakage range for electrolytic hydrogen spans approximately 0.2% (steady-state, best case) to 1.72% (all operational losses included, literature-synthesis average). The 2% default sits above the top of this measured range. It is therefore not a central estimate presented as typical performance, but a deliberately conservative fallback: it is applied only as a penalty where an activity cannot demonstrate its actual losses to within ±20%, and it is set high enough that an activity is always better off measuring than defaulting.

Direction of error. Conservative. The default exceeds the measured range, so it over-states rather than under-states fugitive emissions, and it creates an incentive to monitor accurately.

7.4 | Mass-balance reconciliation uncertainty trigger

Value applied: ±20% of calculated losses

Source. Methodology monitoring provisions (§14.1, §8.5). No single external standard fixes this threshold; it is a monitoring-tolerance choice.

Derivation. The trigger determines when an activity must abandon its measured hydrogen-loss figure and apply the 2% default (§7.2). A tolerance of ±20% on a mass-balance reconciliation is consistent with the measurement uncertainty achievable on custody-transfer and process metering for a gas as light and leak-prone as hydrogen, where small unaccounted flows are a large fraction of total losses. Set tighter (for example ±10%), the default would trigger even for well-monitored activities, penalising good practice; set looser, an activity could carry a poorly-constrained loss figure into the crediting calculation. ±20% balances the two, and pairs with a conservative default so that triggering it is never advantageous.

Direction of error. Conservative in effect. Because the consequence of exceeding the trigger is the above-range 2% default, the threshold errs towards applying the conservative fallback.

7.5 | Grid transmission & distribution losses (TDL)

Value applied: 0.10 (10%)

Source. Applied where official verifiable grid-loss data is unavailable (parameter GHM, TDL_y). Reference: IEA and World Bank compilations of national transmission-and-distribution loss rates.

Derivation. Reported T&D losses vary widely by country — of the order of 4–6% in efficient OECD grids, and 15–20% or higher in some developing-country grids. A single global default of 10% sits toward the upper end of the distribution for the grids on which these activities are most likely to be sited, without adopting an implausible worst case. It applies only as a fallback where the activity cannot provide verified country data; an activity on an efficient grid is better off providing its actual (lower) figure.

Direction of error. Conservative where TDL increases the deduction. A higher assumed loss increases the grid-electricity emissions attributed to the activity for the fraction of supply drawn from the grid, reducing net credits.

7.6| Transport de-minimis distance

Value applied: 200 km (two-way)

Source. Methodology Section 8.7 (eq.13): below 200 km two-way, activity transport emissions may be set to zero.

Derivation. The test is one of materiality, below what distance are transport emissions negligible against the baseline they offset? For hydrogen delivered by road at a representative freight emission factor, 200 km of two-way transport contributes emissions that are a small fraction of one percent of the ~8.5 tCO_2/tH_2 baseline — well within the noise of the baseline itself. Above 200 km the emissions are calculated explicitly (eq.13), so the de-minimis does not exempt genuinely material transport; it exempts only distances at which calculation would add burden without changing the result.

Direction of error. Immaterial at the threshold. The exempted quantity is negligible relative to the baseline; setting it to zero neither over- nor materially under-credits.

7.7| Renewable allocation threshold

Value applied: ≥70% of net annual generation

Source. Methodology §3.2.6: a renewable facility serving the activity and other consumers shall allocate at least 70% of its net annual generation to the activity.

Derivation. The threshold ensures that the renewable facility is predominantly dedicated to the activity rather than an incidental supplier, so that the attribution of its generation to the activity is credible and the risk of the same generation being claimed by other consumers is limited. Seventy percent is high enough to establish predominant dedication while permitting the normal operational reality that a facility cannot allocate 100% of variable output to a single load without curtailment. It operates together with the temporal-matching and deliverability conditions (Section 6), which do the substantive integrity work; the 70% threshold is the attribution floor beneath them.

Direction of error. A higher dedication requirement reduces the scope for double-attribution of shared generation.

7.8| Renewable Commercial Operation Date (COD) window

Value applied: 36 months of PIS

Source. Methodology §3.2.5(b)(i): the renewable facility's COD shall fall within a defined window of the hydrogen facility's Placed-In-Service date.

Derivation. The window enforces the additionality link between the renewable capacity and the activity: the renewables must be built in close temporal proximity to the activity for the activity to be credibly the cause of their construction. The EU RFNBO framework adopts 36 months for the equivalent requirement (Delegated Regulation (EU) 2023/1184), which is the basis for the value as drafted. Decision PD-2 harmonises this methodology with the Green Ammonia methodology at 24 months, with an evidenced 12-month extension to 36 where external delay is documented. The derivation supports both: 24 months as the harmonised default tightens the additionality link, and the 36-month ceiling matches the RFNBO precedent and accommodates documented grid-connection and permitting delay.

Direction of error. A shorter window strengthens the causal link between the activity and the renewable build; the evidenced extension prevents the window excluding activities delayed by factors outside the developer's control.

7.9| Potable-water cap

Value applied: 5% (two-condition: 5% of demand OR 5% of municipal capacity)

Source. Methodology §3.2.9: abstraction of municipal potable water or community-aquifer water shall not exceed the lesser of 5% of the activity's annual water demand or 5% of the documented annual capacity of the local municipal supply.

Derivation. This is a safeguard threshold, not an emission factor; its basis is the protection of community water access rather than a physical derivation. The two limbs bind in different circumstances (as recorded in change log item GH-20): the first scales with the activity and prevents the activity's own water use being dominated by potable sources; the second scales with the community system and is the only limb that binds where a large activity sits beside a small municipal supply — precisely the case the safeguard exists for. Five percent is a conventional threshold for "non-material" abstraction relative to a protected resource, consistent with the precautionary standard in GS4GG Safeguarding Principle 8.

Direction of error. Conservative (safeguard). Retaining both limbs, and taking the lesser, is the more protective construction; the compliance burden is a single utility capacity declaration.

7.10| Grid electricity cap and disqualification triggers

Value applied: 10%; 15% single-year; three-in-five-year

Source. Methodology §3.2.3: annual grid-electricity consumption shall not exceed 10% of total annual consumption; exceeding 10% in three years of a five-year period, or 15% in any single year, without an approved corrective-action plan, may result in disqualification.

Derivation. The 10% cap bounds the fraction of the activity's electricity that may come from the general grid rather than dedicated renewables, preserving the zero-emission premise while allowing for outages and start-up. The two triggers convert the cap from a soft target into an enforceable limit: the 15% single-year trigger catches an acute breach, and the three-in-five-year trigger catches persistent reliance that stays just under the annual cap. Both are calibrated to distinguish genuine operational exceedance (a bad year, addressed by a corrective-action plan) from structural dependence on grid electricity (which defeats the methodology's premise). Decision PD-6 adds the requirement, harmonised with the Green Ammonia methodology, that grid electricity within the 10% cap qualifies only where the grid emission factor is below 0.2 tCO_2e/MWh; the cap and the intensity gate operate together.

Direction of error. The cap and triggers constrain grid reliance; the intensity gate further ensures that permitted grid electricity is genuinely low-carbon. Grid emissions within the cap are in any event fully accounted under §8.3.

7.11 | Embodied-emissions quantification basis

Value applied: EPD (ISO 14025/14040) or conservative IPCC/IEA median defaults

Source. Methodology §9.4 (eq.16): upfront embodied emissions of electrolysers, renewable plant and storage shall be quantified using verified Environmental Product Declarations compliant with ISO 14025/14040, or conservative IPCC/IEA median defaults, and amortised across the crediting period.

Derivation. This default is a source hierarchy rather than a single number, because embodied emissions vary by manufacturer, technology and supply chain. The hierarchy prefers activity-specific verified data (an EPD to a recognised ISO standard) and falls back to conservative institutional medians (IPCC/IEA) where an EPD is unavailable — so that an activity cannot understate embodied emissions by omission. The amortisation basis is set by change log item GH-42: following the G-RESET treatment, the total upfront footprint is amortised over N = the lesser of the technical lifetime and the aggregate crediting period (capped at 15 years), so that it is fully recovered within the crediting period rather than assigned wholly to the first period. The consequential deletion of the CP2/CP3 zero-embodied provision is addressed in the methodology redline.

Direction of error. Full inclusion of embodied emissions as leakage, with a fallback to conservative medians where activity data is absent, errs towards a higher deduction. The G-RESET amortisation with its deficit-ledger companion (GH-57) ensures the full footprint is recovered and not extinguished by an annual floor.

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8.| SECTION 8 — UNCERTAINTY ASSESSMENT AND THE UNCERTAINTY ADJUSTMENT FACTOR

8.1| Method

Framework. The IPCC 2006 Guidelines (2019 refinement), Volume 1, Chapter 3, provide two methods for combining parameter uncertainties: Approach 1, analytical error propagation by root-sum-of-squares; and Approach 2, Monte Carlo simulation. The Guidelines direct that Approach 2 be used where the combining function is non-linear, where distributions are non-normal, or where uncertainties are large — the conditions under which Approach 1's assumptions fail. The brownfield baseline of this methodology contains a non-linear MIN operator (Section 8.3), so Approach 2 is the appropriate method. It is used throughout this section, with Approach 1 reported alongside as an analytical cross-check.

Confidence basis. The IPCC uncertainty object is the two-sided 95% confidence interval. Consistent with the GS4GG conservativeness convention, the discount applied to the baseline is the one-sided 90% lower bound — the tenth percentile of the simulated baseline distribution — expressed as the shortfall from the mean. This errs in the conservative direction: the baseline is set below its expected value by the amount of downside uncertainty at the 90% level.

Distributions. Following the IPCC treatment: a parameter known only by an instrument's maximum permissible error (a bound, not a central estimate with spread) is represented by a uniform distribution across that bound; a parameter known as a central estimate with a spread (the measured historical emission factor) is represented by a normal distribution. This is the IPCC-consistent choice and is more conservative in the tails than treating a bound as the two-standard-deviation width of a normal.

Scope. A parameter enters the aggregation where it carries a genuine statistical uncertainty that is not already offset by an embedded conservative choice. A fixed default is carved out only where its conservativeness is demonstrably already banked. The classification is set out at section 8.2 and the carve-outs are justified individually.

8.2| Parameter classification

The emitting baseline is the product of hydrogen produced and a baseline emission factor. The parameters are classified as follows.

Parameter	Type	Uncertainty	In / carved out	Basis

P_{H2} (hydrogen produced)	Metered	MPE ±1.5% (OIML R139-1 class 2)	IN	Metering uncertainty; uniform across ±1.5%.
EF_{BAT} (8.5 / 18.0)	Fixed default	—	CARVED OUT	Not a sampled quantity. Set at the lower bound of the BAT range with upstream methane excluded; the conservatism is already banked. Aggregating a nominal uncertainty here would double-count it.
EF_{hist} (brownfield only)	Measured (3-yr)	~±5% (CO_2/H_2 ratio)	IN	Measured from CEMS and production metering; genuine, uncounted uncertainty. Normal, σ ≈ 2.5%.
Grid electricity	Metered	MPE ±0.5% (IEC class 0.5)	IN (activity)	Genuine revenue-metering uncertainty; uniform across ±0.5%.
Fugitive H_2 volume	Metered / inferred	~±1.5%	IN (activity)	Same metering class as production.
GWP_{H2} (14.4); TDL (0.10)	Fixed defaults	—	CARVED OUT	Conservatism banked in the default choice (upper-bound GWP; upper-bound loss). Double-count if aggregated.

8.3 | Baseline uncertainty — Monte Carlo (Approach 2)

The simulation uses 100,000 iterations and a fixed random seed (20260729), so that the result is reproducible and a validation and verification body can regenerate it identically. Production is normalised to one tonne of hydrogen; the result is a percentage and is scale-free.

8.3.1 | Greenfield baseline

The greenfield baseline is $P_{H2} \times EF_{BAT}$. With EF_{BAT} carved out (entering as the fixed default constant), the only stochastic parameter is P_{H2}. The baseline distribution is therefore that of the hydrogen meter alone.

$$BEunadj = P_{H2} \times EF_{BAT} \quad (EF_{BAT\ constant};\ P_{H2} \sim \text{Uniform } \pm 1.5\%)$$

Quantity	Value

MC one-sided 90% lower-bound deduction	1.20%
Two-sided 95% interval (information)	±1.42%
Approach-1 RSS cross-check	1.50%
Greenfield baseline UAF	0.988 (i.e. BE_adj,UNC = BE_unadj × 0.988)

8.3.2| Brownfield baseline — the non-linear case

The brownfield baseline is PH2 × MIN(EFhist, EF_BAT). The MIN operator is non-linear, which is precisely the condition for which IPCC Approach 2 exists: Approach 1 cannot represent it, because whether EF_hist or the EF_BAT cap binds depends on the draw. The simulation applies the MIN each iteration.

BE_unadj = P_H2 × MIN(EF_hist, EF_BAT)

The result depends on how close the activity's historical intensity sits to the BAT cap. Two regimes are shown, because the value is activity-specific and both must be understood:

Regime	EF_hist example	Cap binds in	MC 90% lower-bound deduction	Two-sided 95%
Cap idle (historical well below BAT)	7.6 vs 8.5	0.0% of iterations	3.38%	±5.19%
Cap binding (historical near BAT)	8.2 vs 8.5	7.2% of iterations	3.31%	±4.80%

Where the historical intensity is well below the cap, the cap does no work, the baseline is governed by the two measured parameters, and the deduction is approximately 3.4%. Where the historical intensity is near the cap, the cap truncates the upper tail of EF_{hist} — the effect the MIN is there to capture — and the two-sided interval narrows (from ±5.2% to ±4.8%). The one-sided deduction is similar across the two only because the truncation acts mainly on the upper tail, which the lower-bound discount does not read; its effect is visible in the two-sided interval. The point for the methodology is that there is no single brownfield number: the value must be computed for each activity from its own historical data against the applicable cap.

8.4| Activity-emissions uncertainty

Activity emissions are assessed as a separate aggregation, per the decision to treat baseline and activity uncertainty independently. The monitored activity parameters are grid electricity (uniform ±0.5%) and fugitive hydrogen volume (uniform ±1.5%); GWP_{H2} and TDL are carved out as fixed defaults. The simulation gives a one-sided 90% lower-bound deduction of 0.61%.

Leverage on net reductions. Because activity emissions are small relative to the baseline in a green hydrogen activity, this adjustment has limited effect on the net emission reduction. It is derived and stated separately because the decision required it and the uncertainty is real; its magnitude is reported.

8.5 | Summary of the uncertainty adjustment

Aggregation	Treatment	Adjustment (one-sided 90%)
Greenfield baseline	Fixed default — structurally one parameter (P_{H2})	1.2% deduction (UAF 0.988)
Brownfield baseline	Prescribed method — activity runs Approach 2 on its own EFhist vs the cap	Activity-specific; worked example ≈ 3.4%
Activity emissions	Fixed — standard metering classes	0.6% deduction

In each case the fixed defaults (EF_{BAT}, GWP_{H2}, TDL) are carved out with the reason stated, because their conservatism is already banked in the choice of the default. The adjustment is applied where uncertainty is genuine and uncounted, satisfying PD-5, without double-counting conservatism where it is already present.

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