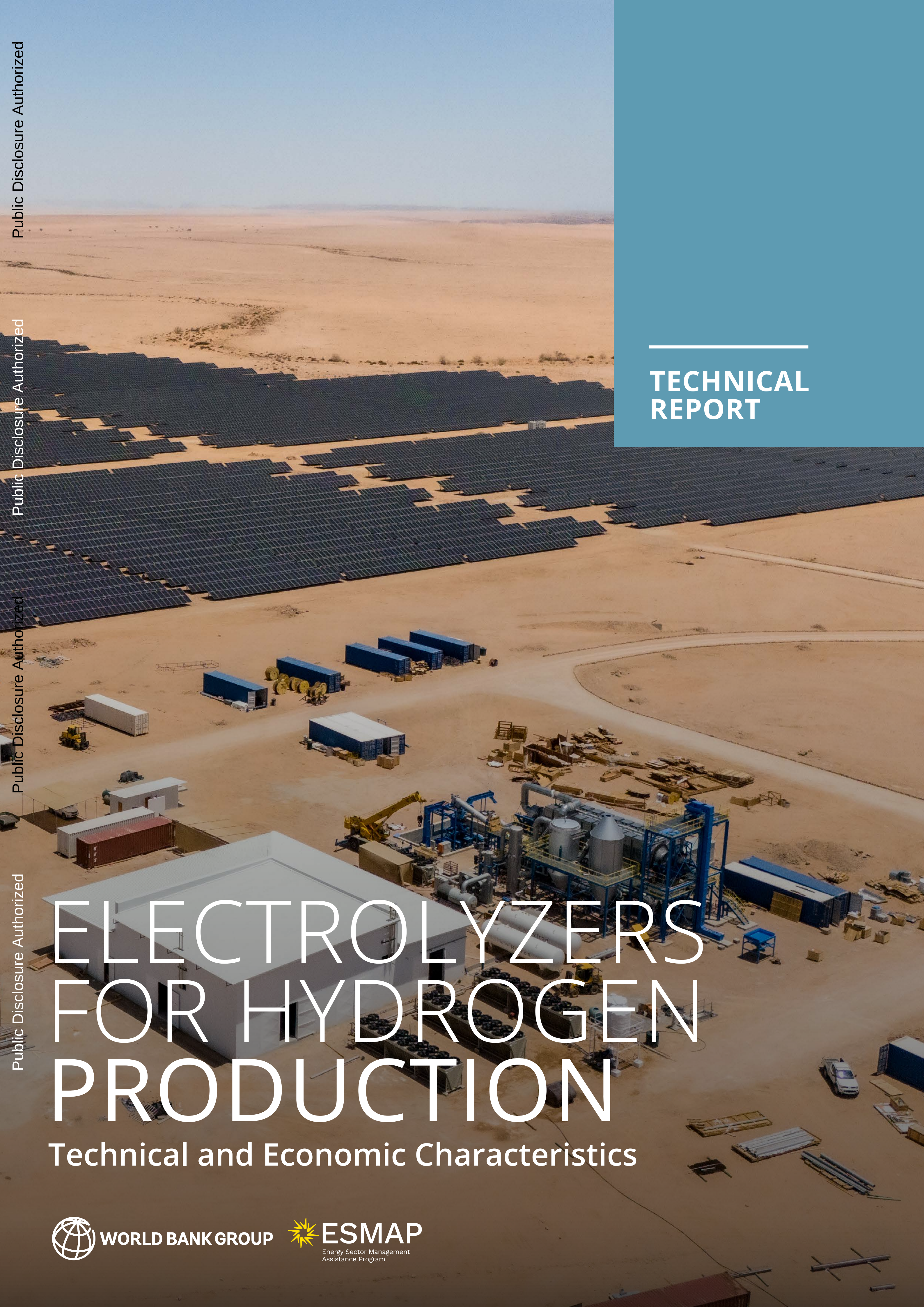

TECHNICAL REPORT

ELECTROLYZERS FOR HYDROGEN PRODUCTION

Technical and Economic Characteristics

WORLD BANK GROUP
ESMAP
Energy Sector Management Assistance Program

TECHNICAL REPORT

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Abbreviations

AC	Alternating current
ACES	Advanced Clean Energy Storage
AEM	Anion exchange membrane
AI	Artificial intelligence
ALK	Alkaline
ASME BPVC	American Society of Mechanical Engineers' Boiler and Pressure Vessel Code
BOP	Balance of plant
BOS	Balance of stack
C&I	Control system and instrumentation
CAPEX	Capital expenditure
CCM	Catalyst-coated membrane
CF	Capacity factor
CIF	Cost, insurance, and freight
COP29	2024 United Nations Climate Change Conference
CRL	Commercial readiness levels
CUF	Capacity utilization factors
DC	Direct current
DEVEX	Development expenditure
DFI	Development finance institution
DNV	Det Norske Veritas
DOE	Department of Energy (United States)
DRI	Direct reduced iron
DSU	Delay in start-up
ECA	Export credit agency
ECHA	European Chemicals Agency
EMC	Electromagnetic Compatibility
EMDC	Emerging Markets and Developing Countries
EPC	Engineering, procurement, and construction
EPRI	Electric Power Research Institute
EU	European Union
FCA	Free Carrier
FID	Final investment decision
GDC	Gadolinium-doped ceria
GIGA-SCALES	GIGA-watt Scaling of advanced Alkaline water Electrolyser Separators
GW	Gigawatt
H2NEW	Hydrogen from Next-generation Electrolyzers of Water
HCD	High-current-density
HEIPA	Hydrogen Energy Industry Promotion Association (China)
HMI	Human-machine interface
HV	High-voltage
IBRD	International Bank for Reconstruction and Development
IDC	Interest during construction
IEA	International Energy Agency
IFC	International Finance Corporation
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization
ISPT	Institute for Sustainable Process Technology
KPI	Key performance indicators
LCD	Low-current-density
LCOH	Levelized cost of hydrogen
LD	Liquidated damage

LHV	Lower Heating Value
LSTK	Lump Sum Turnkey
LTSA	Long-term service agreements
LVD	Low Voltage Directive
MEA	Membrane electrode assemblies
MIGA	Multilateral Investment Guarantee Agency
MNRE	Ministry of New and Renewable Energy, India
MW	Megawatt
NASA	National Aeronautics and Space Administration
NFPA	National Fire Protection Association
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
OECD	Organisation for Economic Co-operation and Development
OEM	Original equipment manufacturer
OPEX	Operational expenditure
PCU	Power conversion unit
PED	Pressure Equipment Directive
PEM	Proton exchange membrane
PFSA	Perfluorosulfonic acid
PGM	Platinum group metals
PLC	Programmable logic controller
PPA	Power Purchase Agreements
PSM	Proton exchange membrane stack module
PV	Photovoltaic
R&D	Research and development
RED	Renewable Energy Directive
REE	Rare earth elements
ROW	Rest of world
SAC	Standardization Administration of China
SCADA	Supervisory control and data acquisition
SECI	Solar Energy Corporation of India
SIC	Silicon carbide
SIGHT	Strategic Interventions for Green Hydrogen Transition
SIL	Safety Integrity Level
SIS	Safety instrumented system
SOEC	Solid oxide electrolyzer cell
TRL	Technology readiness levels
UL	Underwriters Laboratories
VRE	Variable renewable energy
WACC	Weighted-average cost of capital
YSZ	Yttria-stabilized zirconia

All currency is in United States dollars (US$, USD), unless otherwise indicated.

Foreword

« Oui, mes amis, je crois que l'eau sera un jour employée comme combustible, que l'hydrogène et l'oxygène, qui la constituent, utilisés isolément ou simultanément, fourniront une source de chaleur et de lumière inépuisables et d'une intensité que la houille ne saurait avoir. »

Jules Verne – - L'Île mystérieuse[1]

In the year 1800, using recently invented electric batteries, scientists demonstrated electrolysis as a sustained reaction. Water as a source of infinite energy emerged in late 19th century fiction, following the first split of water into its components of hydrogen and oxygen in the late 18th century. In the 21st century, electricity from renewable sources can electrolyze water and provide the hydrogen needed for global decarbonization pathways—particularly for hard-to-abate sectors such as chemicals, steel, and shipping. For emerging markets and many development economies, hydrogen presents an opportunity to harness their abundant renewable resources to support industrial transformation, energy security, and job creation. But it also presents significant challenges given the capital intensity, technical complexity, and financial risks of early-stage deployment at scale.

In our earlier report *Scaling Hydrogen Financing for Development* we examined the economics of hydrogen, but we also recognized the dearth of information on options for electrolysis. Electrolyzers account for a substantial share of project capital expenditure. They also shape operational performance and electricity demand that materially influence the cost of hydrogen. In the nascent hydrogen market, decision-makers face key uncertainties: a fragmented and shifting landscape of technologies, suppliers, cost claims, and commercial models.

With this report we aim to fill that knowledge gap and share our understanding of the status of technologies and their prospects, along with addressing key financial, economics, and environmental questions. Prepared under the World Bank's 10 GW Lighthouse Initiative, launched within the framework of the Breakthrough Agenda under the UNFCC, it provides a rigorous assessment of electrolyzer technologies, market dynamics, cost structures, and supplier offerings.

The analysis is grounded in interviews with more than 50 original equipment manufacturers, project developers, and market participants, complemented by project-level data and World Bank operational experience across multiple regions.

1 *"Yes, my friends, I believe that water will one day be used as a fuel, that the hydrogen and oxygen, which constitute it, used alone or simultaneously, will provide an inexhaustible source of heat and light of an intensity that coal cannot have." Jules Verne –Mysterious Island*.

The analysis shows that soft costs often dominate total installed costs. Engineering, procurement, and construction premiums, financing costs, insurance and risk contingencies, and conservative contractual structures can outweigh differences in stack technology. The report underscores the importance of bankability and execution risk. Moreover, electricity costs remain the dominant driver of the final cost of hydrogen. Electrolyzer choices matter insofar as they enable access to the lowest-cost power. These findings have important implications for policy makers, financiers, and developers alike. They suggest that meaningful cost reductions can be achieved through better project structuring often without waiting for breakthroughs in core technology. Nevertheless, the lessons from developing clean energy technologies and their cost reductions are equally valuable for electrolyzers, which have been deployed at quite low levels so far. Supportive policies are required; but they hold also the promise of continuous cost reductions that will contribute to realizing the "abundance vision" of 19th century fiction, while dealing effectively—and economically—with our 21st century energy challenges.

Demetrios Papathanasiou
Global Director Energy
The World Bank Group

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Key Take Aways

Study Context and Market Dynamics

This report is **a state-of-the-art overview of electrolyzer technologies for hydrogen production and their supply.** Prepared under the 10 GW Lighthouse Initiative in support of the United Nations Framework Convention on Climate Change's Breakthrough Agenda, the analysis draws on interviews with more than 50 original equipment manufacturers (OEMs) and project developers.

Electrolyzer demand - Experience with electrolyzers for renewable hydrogen production is growing, but from a low baseline. As of mid2025, approximately 2.15 gigawatts (GW) of electrolyzer capacity was operational worldwide — equivalent to meeting only about 0.2 percent of current global hydrogen demand. A further 16 GW of capacity is under construction, and an additional 3.5 GW has reached FID.

The market is dominated by two technologies: alkaline (ALK) and proton exchange membrane (PEM). In terms of installed capacity, ALK holds a 64 percent share versus PEM's 36 percent. ALK's dominance is more pronounced in the pipeline of projects, where it constitutes 84 percent of projects under construction. PEM represents 11 percent of the capacity to be built. Solid oxide electrolyzer cell (SOEC) and anion exchange membrane (AEM) technologies account for the remaining 5 percent under construction and are emerging as new pathways.

Electrolyzer supply - Global annual electrolyzer manufacturing capacity stands at 61 GW; an additional 16 GW is under construction. Of the existing manufacturing capacity, 43 GW per year (70 percent) is for ALK, while 13 GW (21 percent) is for PEM. The remainder (9 percent) is for other technologies.

A supply-demand imbalance has led to notable manufacturing overcapacity, and many plants are operating below utilization levels. This imbalance has contributed to sectoral consolidation, reflected in recent bankruptcies, restructuring efforts, and merger activity among electrolyzer manufacturers.

Electrolyzer Technologies, Costs, and the Impact on Hydrogen Economics

Several technical factors influence electrolyzer selection and deployment—including system lifetime, compatibility with variable renewable electricity, electrical efficiency, and equipment size. These performance parameters remain dynamic as technologies mature. A clear industry trend across all electrolyzer types is modularization. This design approach improves scalability, reduces installation and balance of plant (BoP) costs, and simplifies maintenance.

However, **integrating electrolyzers with variable renewable energy remains a challenge.** Although PEM systems are technically better suited to handle rapid fluctuations in renewable output, large projects often continue to favor ALK technologies due to their lower cost and greater commercial availability. To manage variability—particularly in off-grid configurations—developers are adopting strategies such as hybrid solar-wind systems and battery storage to smooth power supply and improve electrolyzer utilization.

Electrolyzer CAPEX structure. The capital expenditure (CAPEX) of an installed electrolyzer system consists of direct CAPEX (stack, balance of stack (BoS), and BoP) and indirect CAPEX (engineering, procurement, construction (EPC); installation; and other associated costs). Both components play an equally important role in determining total project cost.

Current cost ranges vary by technology and manufacturing origin. Lowest quoted systems cost in EMDCs range from $800/kilowatt (kW) to $1,000/kW for ALK and from $1,000/kW to $1,200/kW for PEM. However, cost vary widely, with smaller systems often costing substantially more on a per kilowatt basis. SOEC and AEM technologies are currently the most capital-intensive options due to earlier-stage commercialization and lower manufacturing scale. Cost and price information is of limited value as the scope of what is included varies. For example, in-house engineering skills may eliminate the need for an EPC contractor. Also, the after-sales service and technology bankability can be important aspects. As global manufacturing capacity expands and improvements come to materials use, design optimization, and component standardization, **further reductions are expected in installed electrolyzer costs.**

Key drivers of the levelized cost of hydrogen (LCOH). The best projects today can produce hydrogen at around $3 per kilogram (kg), but most projects face higher hydrogen production costs. A robust analysis of the LCOH is essential for any evaluation of technology options. Such an analysis must account for total CAPEX and operational expenditure (OPEX), including costs associated with managing renewable variability.

Electricity is the most significant OPEX and a key driver of project economics. Meanwhile, electricity supply cost and prices are highly dependent on location. The operational flexibility of electrolyzers can enable efficient utilization of low-cost power, which reinforces the need to align technology selection and system design with local energy profiles. Developers are adapting hybrid designs and battery storage. Grid-connected projects that rely on power purchase agreements may face a different situation in terms of electrolyzer choice than projects operating with their own renewable energy assets.

The greatest CAPEX cost reduction opportunities lie not in the electrolyzer stack itself, but in the BoP, construction, and system integration. Indirect CAPEX—especially EPC and building costs—often presents more room for savings than the stack, where most research and development is now concentrated. Cost data for installed electrolyzer systems suggests notable economies of scale. Less established electrolyzer technologies present a higher technology risk and may therefore face higher financing costs unless the risk can be mitigated through warranties, guarantees, or other means.

Recommendations for equipment selection and due diligence

A holistic approach to electrolyzer procurement is essential. Buyers should evaluate systems not only on headline efficiency or stack specifications but also on the full set of technical, operational, and financial factors that determine long-term project value. Key considerations include **clear definition of electrolyze system boundaries; logistics and installation risks; warranty and service structures; feed water and auxiliary infrastructure needs and finally the OEM performance track record.**

Technology selection should then focus on the attributes that most directly influence project economics and operational reliability: **electrical efficiency and operational flexibility; degradation and stack replacement; technology maturity and bankability and finally equipment reliability.** Project design is also shaped by external constraints. **Financing requirements can limit flexibility in system selection and raise overall project costs** — including the need to use established EPC contractors or proven OEM technologies. In addition, **policy frameworks can influence technology choices**, such as local content rules, manufacturing incentives, or eligibility criteria for public support, and procurement strategies. Continuous capacity building among financial institutions and public stakeholders remains essential to keep pace with rapid advances in electrolyzer technologies.


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Executive Summary

Electrolyzers are the cornerstone technology for renewable hydrogen production. They use electricity to split water into hydrogen and oxygen. When produced with renewable electricity sources such as wind, solar, and hydro power, they bring environmental benefits and opportunities for new economic development and job creation in emerging markets and developing countries (EMDCs).

Each year about 100 million tons (Mt) of hydrogen is produced globally, almost entirely from fossil fuels. Achieving a 10 percent renewable market share would require around 100 gigawatts (GW) of electrolyzer capacity. Demand for electrolyzers is expected to rise as new markets for hydrogen and hydrogen derivatives mature, particularly in ammonia and methanol synthesis, steel-making, and shipping fuels.

World Bank and partner institutions have issued a report that concluded that installed cost of electrolyzer systems are critical for renewable hydrogen production cost. However better operational and commercial information is needed for electrolyzers (World Bank, 2024). This new report fills that gap.

This report is a state-of-the-art overview of electrolyzer technologies and suppliers. It is written with project developers, investors, and policy makers in mind, the very ones evaluating and facilitating progress toward the final investment decision (FID). The analysis suggests that no single best electrolyzer technology exists. Technology choice must consider end-use application and power supply characteristics, aspects that are further elaborated in this report.

Prepared under the 10 GW Lighthouse Initiative in support of the United Nations Framework Convention on Climate Change's Breakthrough Agenda, the analysis draws on interviews with more than 50 original equipment manufacturers (OEMs) and project developers. These interviews offer new insights that may diverge, at times, from conventional assumptions found in academic literature or social media. Much of this reporting divergence reflects the rapid innovation and lack of harmonized global data.

Electrolyzer Market Dynamics

Experience with electrolyzers for renewable hydrogen production is growing, but from a low baseline. As of mid-2025, about 2.15 GW of electrolyzer capacity was operational worldwide. This capacity has been sufficient to produce just 0.2 percent of global hydrogen consumption. China represents 56 percent of this capacity, while Europe accounts for 20 percent, with EMDCs responsible for smaller shares. Another 16 GW of capacity is under construction, and 3.5 GW has reached FID.

Project sizes are shifting from installations measured in tens of megawatts (MW) to facilities in the hundreds of megawatts range. This shift toward larger facilities is reshaping operational strategies. Utility-scale plants can optimize performance through stack-level cycling within a multi-unit configuration, allowing individual stacks to ramp up or down in response to power availability and maintenance requirements. Such operational flexibility is not feasible at the single-unit level, where system dynamics are inherently more constrained.

The market is now technologically bifurcated, which is to say largely dominated by two technologies: alkaline (ALK) and proton exchange membrane (PEM). In terms of installed capacity, ALK holds a 64 percent share versus PEM's 36 percent. ALK's dominance is more pronounced in the pipeline of projects, where it constitutes 84 percent of projects under construction. PEM represents 11 percent of the capacity to be built. Solid oxide electrolyzer cell (SOEC) and anion exchange membrane (AEM) technologies account for the remaining 5 percent under construction and are emerging as new pathways. Interesting new technologies, not yet deployed at a significant scale, are beyond the scope of this analysis.

Market projections for 2030 have been revised downward this past year. The latest estimates suggest that only 5–20 Mt of operational hydrogen production capacity would be in place by 2030. Considering both operational and pipeline projects—and factoring in the typical timeline from the FID to commissioning—global operational electrolyzer capacity is likely to remain below 100 GW by 2030—unless the sector receives a more streamlined and coordinated policy push.

Electrolyzer Manufacturing Capacity and Supply Chains

Global annual electrolyzer manufacturing capacity stands at 61 GW, with an additional 16 GW under construction. Of the existing manufacturing capacity, 43 GW (70 percent) is for ALK while 13 GW (21 percent) is for PEM. The remainder (9 percent) is for other technologies. The manufacturing landscape is highly regional: China dominates ALK manufacturing (86 percent), while Europe leads PEM production (54 percent). China, though, is also rapidly expanding into PEM, SOEC, and AEM manufacturing as well. It should be noted that country allocation of manufacturing capacity can be misleading as an electrolyzer system is a complex technology with intricate and often international supply chains.

A supply-demand imbalance has led to significant manufacturing overcapacity, and many plants are operating below utilization levels. This imbalance has contributed to sectoral consolidation, reflected in recent bankruptcies, restructuring efforts, and merger activity among electrolyzer manufacturers. Also, when referring to manufacturing capacity, it is critical to distinguish between stack assembly capacity and the ability to deliver fully integrated systems. While stack manufacturing capacity is abundant, bottlenecks persist for balance of plant (BoP) components such as power conversion and gas treatment units. Data also show that supply chain models differ across OEMs. Some manufacturers produce most or all components and materials in-house, while others rely on external suppliers for key parts.

Electrolyzer Technologies

The ALK electrolyzer category itself is diverse and encompasses a range of configurations, each with unique operational characteristics. Pressurized ALK systems, which dominate the market, feature large stacks managed by a single power unit. This design—commonly adopted by Chinese manufacturers—is trending toward even larger stacks to enhance productivity, though logistical constraints such as transport restrict further scaling. In contrast, atmospheric ALK systems offer greater operational flexibility, capable of functioning efficiently at partial loads as low as 10 percent, compared with the 30–40 percent range typical of pressurized systems. A third, more specialized variant—high-current-density ALK systems—uses advanced catalysts to boost output. These systems are produced by only a few OEMs and have yet to demonstrate cost competitiveness at scale and over time.

PEM electrolysis stacks are smaller and better suited for spatially constrained installations, such as for refueling stations. PEM is also highlighted for the way it handles variable renewables. The narrative positioning PEM electrolyzers as the future standard for large-scale hydrogen production is based largely on their perceived flexibility. But this narrative is being reassessed. Despite theoretical advantages, PEM systems have not yet demonstrated decisive performance benefits in practice, and their persistently high capital costs reduce their appeal for many developers. Evidence from large-scale deployments indicates that projects supplied by intermittent renewable power continue to favor ALK electrolyzers. To manage variability in power supply, some developers are adopting hybrid ALK/PEM system configurations, while others are integrating more battery storage to smooth fluctuations, benefiting from plummeting battery costs. At the multi-stack scale, operational flexibility becomes a less critical differentiator, and ALK technology maintains its dominance in the global project pipeline primarily due to its cost advantages. Innovations such as high-current-density cells and advanced membranes are boosting partial load capabilities, while the scaling of pressurized ALK units at both stack and module levels is driving productivity gains. As the market evolves, technology leadership will be defined not by theoretical advantages but by cost-effective, scalable, and proven solutions that meet the demands of industrial deployment.

Emerging technologies like SOEC and AEM systems offer promising long-term potential. SOECs can reduce electricity consumption by 20–30 percent when integrated into industrial processes that provide waste heat. But they must demonstrate greater durability and cost reductions to achieve commercial viability. AEM systems combine high efficiency and operational flexibility—similar to PEM but without precious metals—but they have yet to prove membrane durability at scale. Both SOEC and AEM are approaching commercial readiness, demonstrating superior performance in key strategic deployments. The primary barrier to their deployment is not technology but risk perception among financiers. OEMs are addressing this skepticism through equity participation and better warranty structures for hydrogen projects.

The electrolyzer industry is steadily increasing modularization across all technology types. Modern integrated modules, which typically range from 5 MW–100 MW, combine multiple stacks with shared systems for power supply, gas processing, and water treatment. This modular approach improves scalability, reduces capital and installation costs, and simplifies both commissioning and long-term maintenance.

System efficiency, expressed in kilowatt-hours per kilogram of hydrogen (kWh/kgH2) is a key determinant of the levelized cost of hydrogen (LCOH). Although ALK and PEM electrolyzers generally exhibit comparable initial efficiencies, PEM stacks tend to degrade more rapidly. As a result, stack replacements in PEM systems can represent up to 15 percent of total system costs, with implications for long-term operating expenditures.

Ammonia production remains the largest end-use segment, representing approximately 42 percent of global projects now under construction. Other major applications include methanol production, hydrogen-based direct reduced iron (DRI), and the use of renewable hydrogen in refineries and refueling infrastructure. Each application imposes specific requirements for hydrogen pressure, flow stability, and purity. These factors directly influence electrolyzer selection. For example, some applications benefit from high-pressure output or additional storage capacity, while others, such as ammonia synthesis, generate waste heat that can be utilized by high-temperature SOEC systems to improve overall efficiency.

This diversity of technical requirements underscores that no single electrolyzer technology can be considered universally superior. Optimal technology selection must instead account for the full system context, including end-use application, integration needs, and characteristics of the power supply.

Table ES.1 summarizes parameters for the different technologies. Apart from cost, several other issues must be considered, including life span, variable renewable electricity integration, electric efficiency, and productivity (space). These parameters are somewhat fluid as technologies evolve.

Water, together with electricity, is a fundamental feedstock for renewable hydrogen production. Although the absolute water requirement per unit of hydrogen is modest—and lower than in fossil-based pathways such as steam methane reforming with carbon capture—its operational and environmental significance remains considerable.

While water contributes only marginally to capital and operating expenditures, its availability and quality are critical to sustainable project development. Responsible management of water resources is therefore essential. Project siting must determine local water availability, purity, and the broader ecological impacts of withdrawal and discharge. In water-stressed regions, reliance on groundwater can exacerbate scarcity, underscoring the importance of alternative sourcing strategies. Technologies such as dry-cooling systems, desalination, and the use of brackish water can slash freshwater demand with minimal effect on the LCOH.

High-purity water is also indispensable for maintaining electrolyzer performance. Contaminants can cause irreversible damage to sensitive components—particularly PEM membranes—leading to faster degradation, reduced efficiency, and unplanned outages. As a result, dedicated purification steps are often required to meet stringent feedwater specifications. Despite this dependency, OEMs typically avoid assuming responsibility for water quality management, leaving developers to ensure robust purification and monitoring systems are in place.

TABLE ES1.

Key Parameters of Electrolyzer Technologies at Scale (Cost Data Reflect Global Ranges)

KEY INVESTMENT PARAMETERS				
PARAMETER	**ALKALINE (ALK)**	**PROTON EXCHANGE MEMBRANE (PEM)**	**SOLID OXIDE ELECTROLYZER CELL (SOEC)**	**ANION EXCHANGE MEMBRANE (AEM)**
CAPEX installed system ($/kW)	500–1,500	1,000–2,000	>3,000	>3,500
Annual nonelectricity OPEX as percentage of total CAPEX	2–3%	3.5–5%	>3%	>5%
ELECTROLYZER LIFETIME				
Stack durability (estimated operating hours)	60,000–90,000	40,000–60,000	20,000–40,000	10,000–20,000
Degradation rate	0.1–0.25% per 1,000 hours	0.2–0.5% per 1,000 hours	0.5–1.0% per 1,000 hours	>1% per 1,000 hours (uncertain)
INTEGRATION WITH VRE				
Minimum load (% of nominal)	30% rated load for pressurized ALK; 10% for modern atmospheric ALK	10% rated load	50% rated load	5% rated load
Cold start time (minutes)	30–120	5–0	>360	20–30
ELECTRICITY DEMAND PER UNIT OF HYDROGEN				
Electricity consumption (kWh/kgH_2, AC)	51–56	53–56	35–42 (with high-T steam available on site)	51–53 (claims; limited field validation)
ELECTROLYZER'S SIZE				
Typical current density (A/cm², stack)	0.23–0.46 (advanced: 0.6–0.9)	1.0–2.0	0.3–1.0	0.5 (emerging)

A = ampere; AC = alternating current; CAPEX = capital expenditure; cm2 = square centimeter; kW = kilowatt; kWh/kgH2 = kilowatt hours per kilogram of hydrogen; OPEX = operational expenditure; T = temperature; VRE = variable renewable energy.

In addition to variable inputs such as electricity and water, the material requirements of electrolyzer technologies also influence system design and technology selection. Different systems rely on distinct inputs—PEM electrolyzers, for example, use platinum group metals such as iridium and platinum, while other technologies require various rare earth elements. Where battery systems are integrated, lithium and related electrochemical materials become additional considerations. Although these materials can affect costs and present localized supply chain risks, previous analyses, including World Bank assessments, indicate that the hydrogen sector's overall material footprint is unlikely to tax the global materials markets.

Electrolyzer Costs and the Impact on Hydrogen Economics

Integrating electrolyzers with variable renewable energy remains a key challenge. Although PEM is better suited for renewable variability, large-scale projects often favor ALK due to cost and availability. Various strategies exist to deal with variability for off-grid systems. Hybrid solar-wind systems and battery storage are increasingly used to stabilize supply. Solar is by far the cheapest form of renewable power available today, in good locations at about USc1/kWh, but generation is limited to daytime. More and more plants are using battery storage in combination with solar power supply. The falling costs of battery-powered energy storage systems allows for economically viable electricity storage for more hours per day—storage that can extend the operating hours of the electrolyzers. Accordingly, fully solar-powered renewable hydrogen generation with ALK is now being considered for some projects. The technical viability of such designs remains to be proven on a commercial scale. Furthermore, innovations such as direct current (DC) coupling of solar photovoltaic (PV) with electrolyzers offer further cost savings.

Electrolyzer CAPEX Structure

The total installed cost of an electrolyzer comprises both direct and indirect capital expenditure (CAPEX). Direct CAPEX includes the stack, balance of stack (BoS), and BoP, while indirect CAPEX covers engineering, procurement, and construction (EPC); installation; and related services. Both categories contribute to overall project costs, and past cost overruns were caused by underestimated or omitted CAPEX components. Broader structural factors—such as inflation, high financing costs, and supply-chain disruptions—continue to place upward pressure on installed costs.

Although central to system performance, the stack typically represents only 20–50 percent of direct CAPEX in modern large-scale PEM and ALK electrolyzer projects. Installation and EPC activities are often the largest cost contributors, accounting for 40–50 percent of total CAPEX, particularly for large projects requiring extensive civil works, permitting, and integration. BoS and BoP elements are also substantial, jointly representing 50–80 percent of direct CAPEX, depending on technology choice and project location.

Significant regional variability persists. Chinese-manufactured ALK systems cost roughly \$270–\$280/kilowatt (kW) for the domestic market and around \$350/kW ex-factory for export, compared with \$800/kW ex-factory for ALK systems produced in Europe or the United States. After including logistics, EPC, civil works, and supporting systems such as water treatment, installed ALK costs in emerging markets range from \$800–\$1,200/kW for Chinese systems and \$1,200–\$1,800/kW for European systems in EMDCs, with higher costs for small-scale installations. It should be noted that cost and price information needs to be understood in the context of project scope. For example, in-house engineering skills may eliminate the need for an EPC contractor.

PEM systems command a notable price premium due to their reliance on platinum group metals such as iridium and platinum. While PEM offers a smaller physical footprint that can reduce building and logistics costs, this only partially offsets higher stack and component costs. As a result, complete Chinese PEM systems typically cost \$700–\$1,000/kW, while European systems range from \$1,000–\$1,600/kW ex-factory. One US supplier offers total PEM installed systems with project capital cost of \$1000/kW, based on higher stack power density to reduce material intensity of platinum group metals and modular construction to lower EPC cost. Installed PEM systems to date generally fall between \$1,850 and \$2,500/kW in China and emerging markets. Regional price variation is lower for PEM than for ALK because PEM systems depend more heavily on globally traded components. The current price range for PEM electrolyzers indicates a substantial cost reduction potential. This will be driven by a number of factors including economies of scale, optimization of catalyst use and stack recycling at the end of life to recover precious metals.

Market conditions continue to evolve rapidly. Recent auction results in China indicate ALK stack and BoS costs as low as \$100/kW, excluding BoP. This is around 60 percent below 2022 levels, demonstrating the emergence of highly competitive offers that may not always reflect underlying manufacturing costs.

Among newer technologies, SOEC and AEM systems remain the most capital intensive. Current pilot-scale SOEC installations cost \$5,000–\$5,800/kW, far more than ALK and PEM systems. Manufacturers report, however, that industrial-scale SOEC and AEM equipment can now be delivered at under \$2,000/kW. Further cost reductions can be expected as production capacity expands and component standardization improves.

Across global markets, installed costs in Asia remain lower than in Europe, North America, and Australia. These differences are driven less by electrolyzer hardware and more by soft costs, including EPC, financing, risk premiums, and labor. As the sector matures, project developers are realizing that advanced, high-specification technologies are not always necessary; in many cases, proven and cost-effective solutions are sufficient to accelerate near-term deployment.

Key Drivers of the LCOH

A rigorous assessment of the LCOH is central to evaluating electrolyzer technologies and project feasibility. The LCOH must reflect both total CAPEX and operational expenditure (OPEX), including the costs of managing renewable power variability. The biggest opportunities for cost reduction lie not in the electrolyzer stack, where most research and development (R&D) is now focused, but in the BoP, construction, and system integration elements. Installed-cost data also indicate noteworthy economies of scale as project sizes grow from the megawatt to the hundred-megawatt range.

In most projects, OPEX dominates LCOH, with CAPEX playing a secondary role. The most competitive projects today can achieve hydrogen production costs of around $3/kilogram (kg), but the majority still face higher costs. While technology choice can influence LCOH through efficiency gains or lower power supply costs, the major cost levers sit outside the stack itself. For full system deployments, site-specific and integration-related factors often have a greater impact on economics.

Electricity is the largest OPEX component and the primary driver of project economics. Electricity prices are highly location dependent. Although solar PV can be procured at low cost in favorable regions, electrolyzer operation requires higher capacity factors and minimum load thresholds. This often necessitates a mix of renewable sources, battery systems, or pumped storage, raising the effective electricity cost. Transmission charges can add costs. Global average supply costs typically fall in the 3–5 USDcents/kWh range in good locations but can be much higher. It is therefore essential to align electrolyzer technology, system design, and operating strategy with local energy conditions. Developers are adopting hybrid system designs and battery storage to optimize their access to low-cost electricity. Grid-connected projects operating under power purchase agreements face different cost dynamics than fully self-supplied renewable projects.

Financing conditions also play a critical role. An assessment of the weighted average nominal cost of capital across leading emerging and developing countries (EMDCs) shows a range of 9.4–18.4 percent, making financing strategies pivotal for lowering the LCOH. Less mature electrolyzer technologies carry higher perceived technology risk and may therefore face elevated financing costs unless risks are mitigated through warranties, guarantees, or other risk reduction instruments.

Overall, achieving competitive hydrogen production costs requires a holistic approach: optimizing electricity sourcing and flexibility, minimizing indirect CAPEX, capturing economies of scale, and deploying effective financing and risk mitigation strategies.

Cost Reduction Opportunities

Major reductions in LCOH are expected in the coming years. Because electricity accounts for roughly two-thirds of LCOH, the most immediate cost reduction opportunities lie in lowering the cost of power supply. Strategic site selection, better renewable power mixes, and more competitive battery technologies (which enable greater use of low-cost solar PV) are central to near-term improvements.

Although the electrolyzer stack represents a minority of total system CAPEX, it remains a primary focus of manufacturing innovation. Ongoing R&D aims to decrease the use of precious metals in PEM systems and improve electrical efficiency in next-generation designs, with potential efficiency gains of up to 20 percent.

The largest cost reduction potential, however, lies in the BoS and BoP components. Economies of scale, design standardization, containerization, modular skids, and supply chain consolidation can meaningfully reduce costs. Smaller installations continue to face much higher unit costs, underscoring the strong economic advantages of large-scale deployment.

In EMDCs, cost reduction focuses on easing expenditures on EPC and civil works. While first-of-a-kind projects often require full EPC involvement, experienced developers are reducing total project costs by 20–40 percent by limiting EPC scope or bypassing EPC contractors entirely. Although this approach can lower installed costs, it requires strong in-house engineering capability and close collaboration with equipment suppliers. Lender requirements may still necessitate EPC lump-sum turnkey arrangements where developer capabilities or risk mitigation instruments are insufficient.

Manufacturers worldwide are adopting advanced production methods, including automation and design optimization to reduce stack costs. Meanwhile, digital technologies such as artificial intelligence (AI)-enabled automation, digital twins, and predictive maintenance offer opportunities to lower both CAPEX and OPEX by accelerating commissioning, extending stack life, and improving capacity factors.

Better operational track records, stronger performance guarantees, and more standardized modular electrolyzers will reduce risk premiums and improve project bankability.

Finally, policy frameworks continue to shape electrolyzer markets and cost structures. Local content requirements, manufacturing incentives, and industrial strategies can support domestic production but may hike equipment costs when markets contract. International experience with renewables and other clean energy sectors informs us that innovation, competition, and diversified supply chains remain the most effective drivers of long-term cost reduction.

Commercial Aspects

OEM strategies in the hydrogen-electrolysis market vary in product scope, delivery models, and after-sales commitments. Suppliers range from those offering stack-only solutions to OEMs providing stack + BoS packages to a smaller group delivering full BoP systems that include gas purification, drying, thermal management, water treatment, and site-level integration services. Delivery models also differ. Containerized, turnkey module solutions from the International Organization for Standardization (ISO) dominate small-scale projects, whereas large-scale installations rely on skid-mounted systems and on-site assembly of factory-tested modules.

After-sales offerings likewise vary. Most OEMs provide a standard two-year equipment warranty, with optional long-term service agreements and performance guarantees offered at additional cost. Indicative data suggest that full service contracts may add approximately 3 percent of equipment CAPEX per year. Long-term dependence on OEM support remains a concern, given uncertain supplier viability over 10–20-year project horizons, regional limits on service coverage, and limited multiyear operating track records. In several utility-scale projects, electrolyzer performance has diverged from OEM specifications, although some systems now incorporate supervisory control and data acquisition (SCADA)-based remote monitoring and diagnostics to support maintenance and improve reliability.

Feedback from project developers reveals additional execution-related risks not highlighted in OEM marketing material. These risks include delays in equipment delivery, incomplete technical documentation, and difficulty meeting water purity requirements, particularly for PEM systems, when water treatment infrastructure falls outside the supplier's scope.

These observations underscore the need for a holistic evaluation framework when selecting electrolyzer systems. Key considerations include:

- System boundary definition (stack only vs. BoS vs. BoP)
- Installation logistics and integration risks (containerized vs. skid mounted; factory tested vs. field assembled)
- Warranty depth, service contract cost, and supplier durability over the project life cycle
- Auxiliary infrastructure maturity, including deionized water supply, cooling loops, and gas drying
- Real-world performance track record, including long-term stack degradation and operational reliability

The supply landscape is increasingly globalized. Many North American and European OEMs rely on Asian-manufactured components, while Asian suppliers are expanding production and service footprints in major overseas markets to address local-content requirements and logistical constraints. Although some regional specialization persists, distinctions across supply regions are becoming less pronounced as global supply chains mature.

Recommendations for Equipment Selection and Due Diligence

There is no universal best electrolyzer technology. ALK systems nevertheless show the lowest capital costs with comprehensive offerings. Some suppliers include installation support, which can reduce or even eliminate the need for EPC contractors resulting in potential cost savings.

Regarding the design of hydrogen projects, several factors must be evaluated: total installed cost, operational expenses, technology maturity and risk, the OEM offering in its totality, service and warranty provisions, electrical efficiency, degradation rates, and minimum load capabilities. These parameters are critical in selecting the most suitable technology for a given context.

At present, OEM offerings are not standardized, so due diligence is essential. Policy makers and investors must define system boundaries—such as stack, BoS, BoP, and installation scope. This is crucial for benchmarking CAPEX and for fairly comparing technology providers. Many general reports present cost estimates based on a host of assumptions that can skew conclusions. A harmonized approach to CAPEX benchmarking is needed to support informed decision-making.

Policy interventions also play a role in shaping market dynamics. Measures such as local content requirements for electrolyzers can influence technology selection and pricing. While these policies may support domestic industries, they can also lead to higher equipment costs if not carefully designed.

The analysis suggests that lessons learned from upscaling and cost reduction with other forms of mass manufactured clean energy technologies also apply in the case of electrolyzers. Policy efforts need to focus on technology innovations to reduce electrolyzer cost, strategies that enable integration of low cost renewable electricity, and market support for clean hydrogen and derivatives, using financial incentives and a premium price. At the same time this should be combined with appropriate carbon pricing for conventional hydrogen.

Proprietary databases can provide valuable insights to support informed technology selection. For example, the one operated by Det Norske Veritas (DNV) tracks 165 electrolyzer parameters. These platforms offer detailed, standardized data that can help policy makers and developers assess equipment performance, reliability, and cost-effectiveness.

This report presents a five-step methodology for selecting an electrolyzer supplier, integrating both technology choices and supplier-specific considerations. Figure ES.1 summarizes the approach.

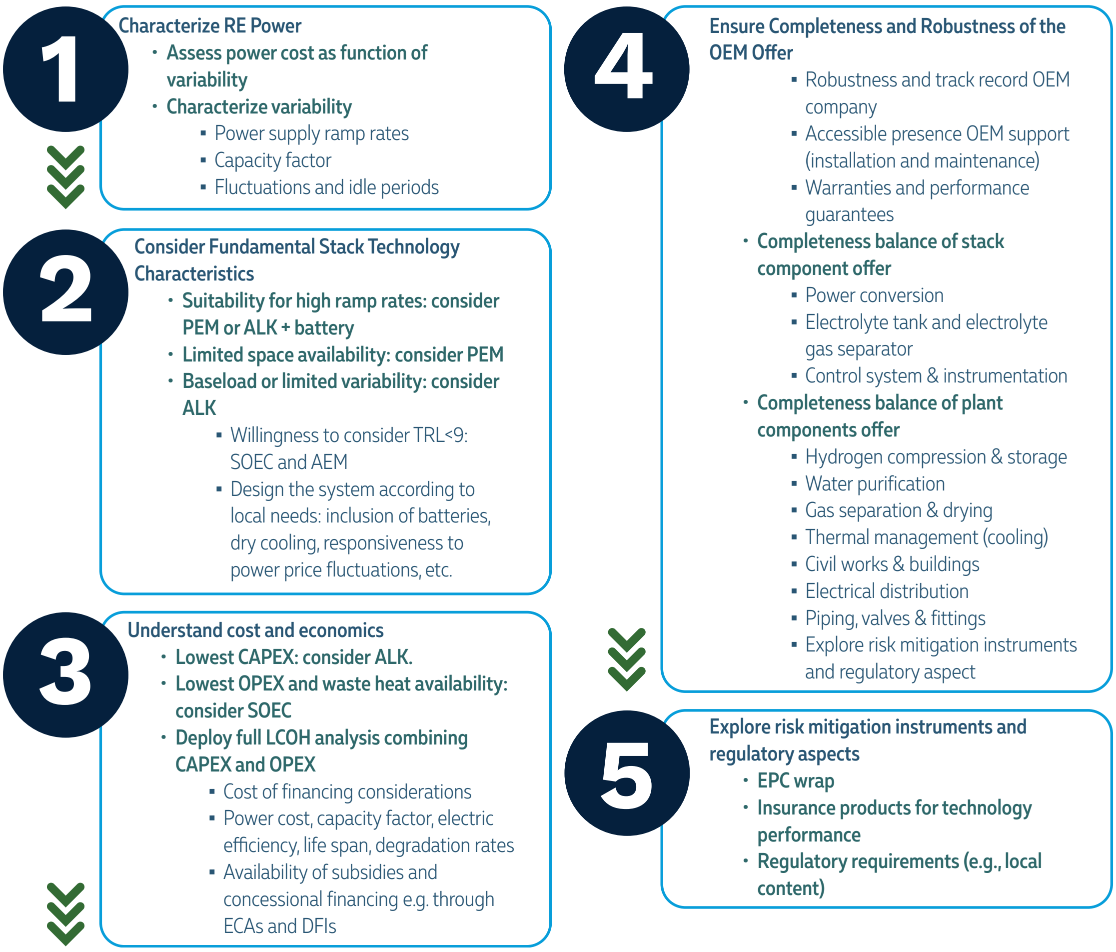
The electrolyzer technology affects CAPEX, OPEX, and revenue streams. When choosing among the various technology options, decision-makers would do well to consider the following factors:

- **Electrical efficiency.** The amount of power required per unit of hydrogen will affect total electricity demand and LCOH.
- **Operational flexibility.** Electrolyzer capability for flexible and intermittent operation can be critical, notably when low-cost variable PV and wind power sources are deployed.
- **Degradation and stack replacement**. Efficiency losses and the cost and frequency of stack replacements are major OPEX components.
- **Technology maturity and bankability.** Limited experience with long-term, large-scale electrolyzer operation heightens project and financing risks. Long-term service agreements, warranties, and insurance instruments are critical as contractual mitigants.
- **Equipment reliability.** The performance and reliability of OEMs vary widely across a range of factors that include scope of supply, after-sales service, warranties, and performance guarantees.
- **Financing constraints.** Commercial banks and development finance institutions often impose eligibility requirements like the use of EPC contractors or proven OEM technologies. These restrict how project design addresses the concerns of demand flexibility and energy efficiency. They also affect the cost structure of projects, increasing costs.

- **Policy framework.** The choice of equipment manufacturing location may also be affected by local content requirements, subsidies, and other support policies. Finance institutions require continuous capacity building and regular knowledge updates so they can stay abreast of technology innovations.

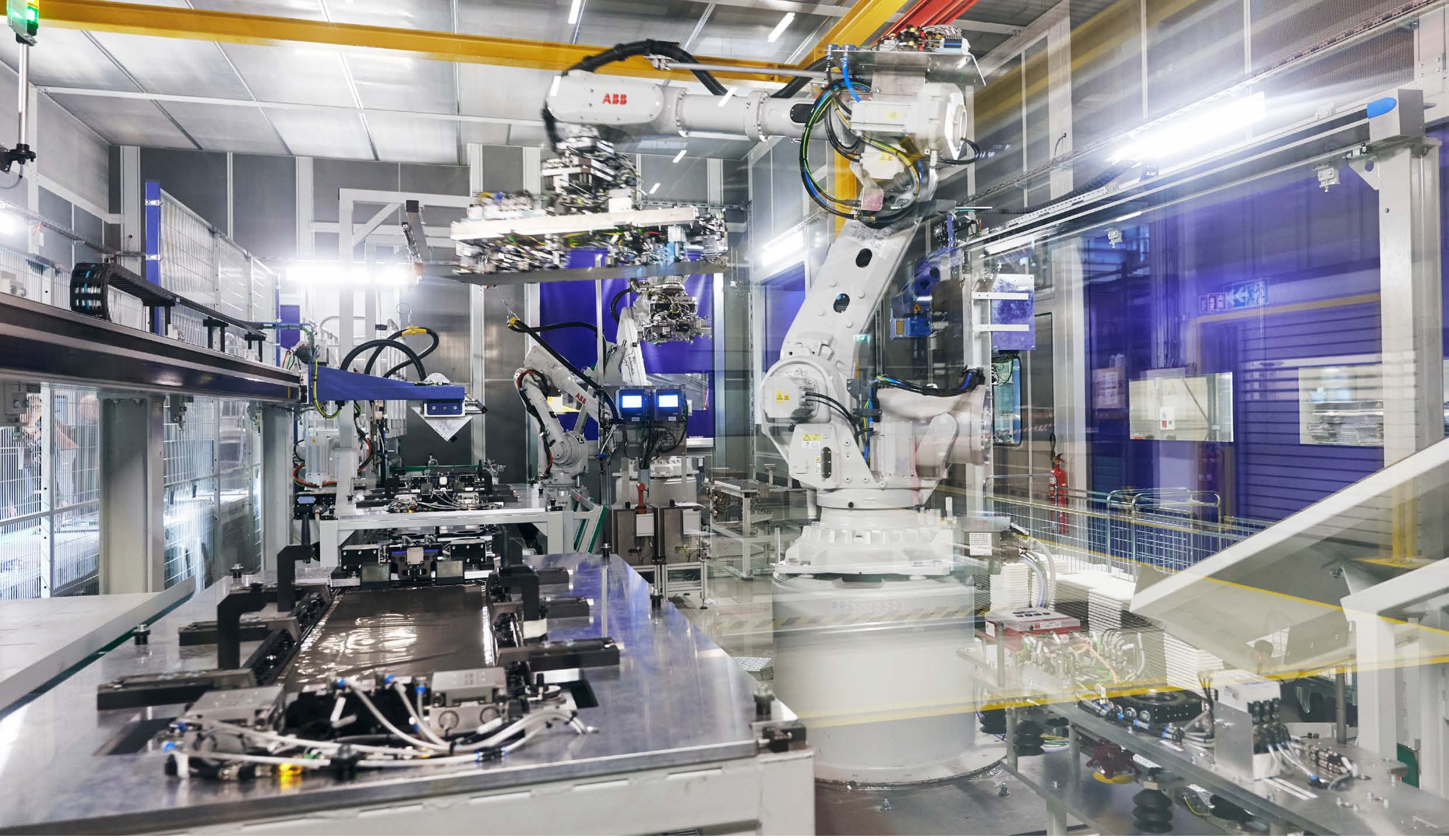
FIGURE ES.1

A methodology for selecting electrolyzers



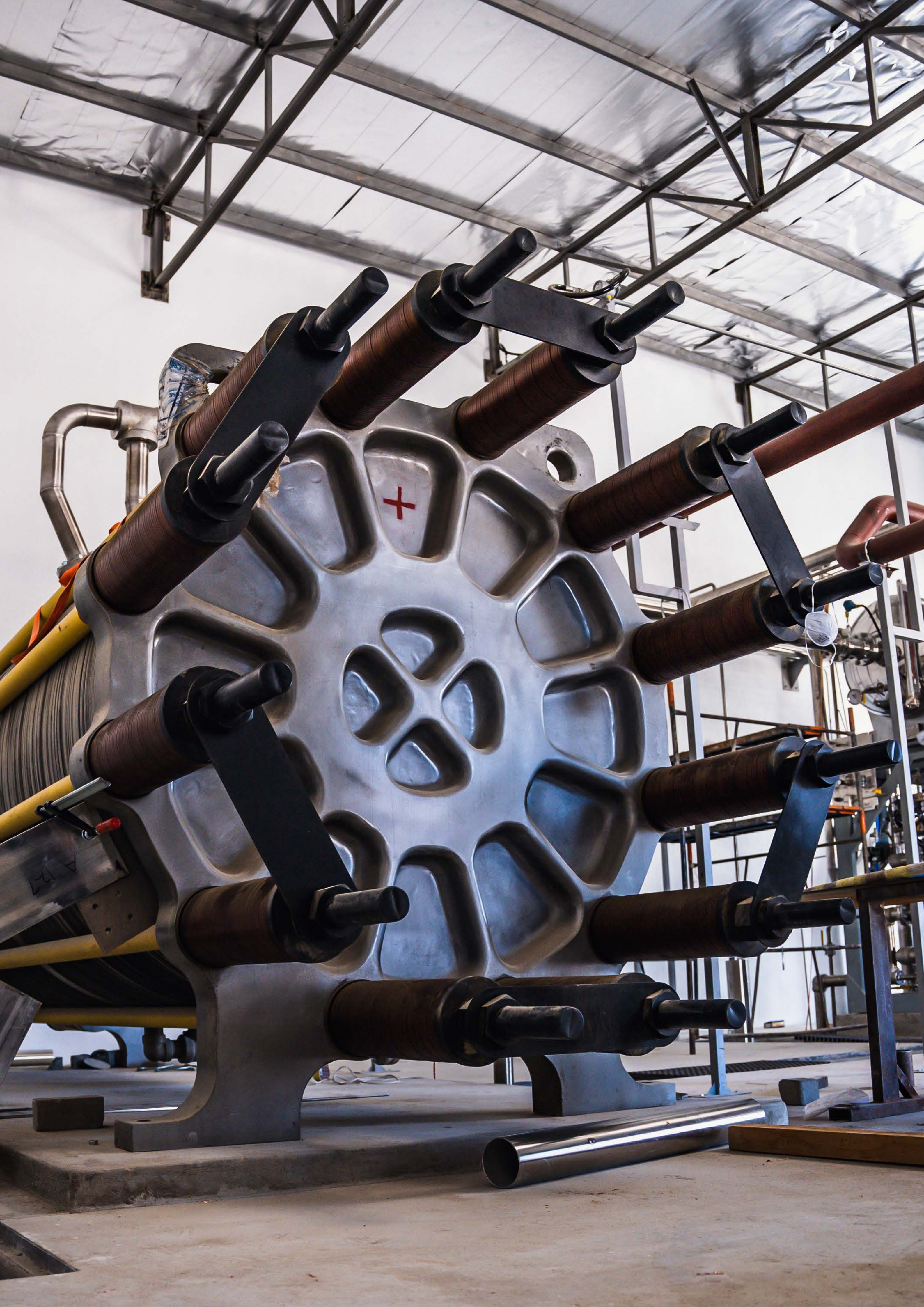
Source: World Bank staff analysis.

Note: AEM = anion exchange membrane; ALK = alkaline; CAPEX = capital expenditure; DFI = development finance institution; ECA = export credit agency; EPC = engineering, procurement, and construction; LCOH = levelized cost of hydrogen; OEM = original equipment manufacturer; OPEX = operational expenditure; PEM = proton exchange membrane; RE = renewable energy; SOEC = solid oxide electrolyzer cell; TRL = technology readiness level.



Caveats and Future Research

This analysis provides only a snapshot of a fluid technology. There is growing recognition that as the sector develops, standardized and quality information will be critical. The validity of information available today is not always clear and often contradictory. The paucity of real-world, large-scale, and multiyear applications make it difficult to issue definitive statements about technology choices. While commercial databases can support due diligence, there is limited performance information in the public domain. But as more projects come on stream, the situation will improve. The analysis highlights the capability to integrate variable renewables as a key factor. A lot of electrolyzer system innovation targets better integration, allowing systems to tap into low-cost renewables. Monitoring new system design performance is warranted. Costs are also changing rapidly, so continuous monitoring and benchmarking will be needed to assess the latest progress so decision-makers can interpret the available information correctly.



About this Report

Context of the Report

This report is a deliverable under the World Bank's 10 GW Lighthouse Initiative, launched under the Breakthrough Agenda of the United Nations Framework Convention on Climate Change held at the 2024 United Nations Climate Change Conference (COP29) in Baku. The initiative aims to accelerate the deployment of renewable hydrogen in emerging markets and developing countries (EMDCs). In this regard, the final investment decision of 10 gigawatts (GW) of renewable hydrogen electrolyzer capacity—equivalent to more than five times the electrolyzer capacity now in operation worldwide—will focus on viable industrial projects that have lower financing costs and lend themselves to large-scale adoption.

By focusing on EMDCs, the 10 GW Lighthouse Initiative seeks to enhance energy security, support net-zero pathways, boost industrial decarbonization, and stimulate socioeconomic development. Its distinct feature lies in the participation of 15 development financing institutions, including three entities of the World Bank Group: the International Bank for Reconstruction and Development, International Finance Corporation, and Multilateral Investment Guarantee Agency. Together, these institutions offer financial resources, technical expertise, and risk-mitigation instruments that help build innovative financing structures capable of mobilizing private capital at scale.

The World Bank Group's renewable hydrogen portfolio will expand accordingly. Between 2023 and 2024, the International Bank for Reconstruction and Development committed nearly $1.5 billion annually in financing for renewable hydrogen and associated infrastructure, while the International Finance Corporation moved five hydrogen projects toward completion and granted initial support to approximately eight more projects.

Rationale and Objective of the Report

Renewable hydrogen production projects generally require generous financing, which covers up-front capital expenditure (CAPEX) and supports the high cost of capital, both acute challenges for EMDCs. A critical component of this cost structure is the electrolyzer, the core technology for splitting water into hydrogen. Beyond the initial investment, of paramount concern is the efficiency of the electrolyzer. Efficiency dictates both the amount of renewable electricity required per unit of hydrogen produced and the final levelized cost of hydrogen (LCOH).

World Bank and partner institutions have issued a report that concluded that installed cost of electrolyzer systems are critical for renewable hydrogen production cost. However better operational and commercial information is needed for electrolyzers (World Bank, 2024). This new report fills that gap.

Real-world data on the long-term performance, reliability, and maintenance of large-scale electrolyzers are limited, especially under the climatic and grid conditions prevalent in many EMDCs. The selection, procurement, and operation of this technology are therefore key to project viability and must be rigorously scrutinized by project developers as well as financiers seeking to de-risk their investments.

This report has been developed to serve as a practical guide for project developers, financial institutions, and policy makers engaged in hydrogen projects to look for clear, reliable, and up-to-date technical insights into hydrogen electrolysis systems. It offers evidence based on interviews with key sector players, original equipment manufacturers (OEMs), and hydrogen project developers (Box AR.1). It also presents recently gathered scientific literature, specialized media, and manufacturer specifications. Taken together, these offer a fresh snapshot for stakeholders assessing the technology's feasibility, budgeting, and competitiveness. The analysis has also benefited from unique World Bank insights into leading renewable hydrogen projects being developed in EMDCs.

The report also provides data and criteria for comparing and evaluating offers from various OEMs, which should strengthen due diligence, negotiation, and bankability assessments. Additionally, the report aims to clarify prevalent market misconceptions. The renewable hydrogen sector is evolving rapidly, so outdated assumptions about cost, technological maturity, and system integration may affect project development and decision-making. The report offers up-to-date facts on technology performance, cost drivers, and commercial conditions.

The report also presents a methodology for selecting an electrolyzer supplier, factoring in considerations related to technology choices and specific to suppliers (Figure AR.1).

The first step in this methodology involves the power supply profile, which more or less governs the choice of electrolyzer technology. For off-grid systems, the electrolyzer tracks the variability of renewable resources; grid-connected plants sync operations to time-of-day pricing—for example, high-cost evening peaks versus low-cost daytime solar. Once the power supply is defined, the electrolyzer stack technology is selected based on its compatibility with expected operating conditions (chapter 1).

The second step is a technoeconomic assessment that looks at the CAPEX, operational expenditure (OPEX), efficiency, degradation, and operating profiles to estimate the LCOH for each viable option, narrowing the selection to the most cost-effective technologies (chapter 2). Technologies continue to evolve rapidly which impacts performance and cost, which in turn can impact technology choice. These aspects are discussed in chapter 3.

BOX AR.1

THE STAKEHOLDER INTERVIEW PROCESS

The report draws on insights from renewable hydrogen project developers and electrolyzer original equipment manufacturers (OEMs) across the globe. These insights were gathered through structured interviews conducted with representatives of the participating organizations under Chatham House rules. In total, around 20 OEMs, 20 project developers, and 10 other stakeholders such as engineering, procurement, and construction contractors were interviewed between March and November 2025 (see Acknowledgements section for stakeholders consulted). Organizations were selected based on their market share, geographic footprint, and the scale of their project portfolios.

This was not a rigorous scientific exercise. The following gives a sense of the questions that were posed to the OEMs. Questions were adapted based on interviewee expertise:

- What is the realistic outlook for electrolysis system cost reductions in the short and medium term?
- What are the main challenges to reducing electrolyzer costs?
- From a technology point of view, are there performance differences between alkaline (ALK) and proton exchange membrane (PEM) technologies (mature technologies)? How do atmospheric vs pressurized ALK compare? What about other alternative technologies?
- From a cost perspective, how do ALK and PEM technologies compare? Are there differences in prices between European and Asian manufacturers?
- What role can guarantees play in de-risking electrolyzer technology performance?
- Are technology guarantees, spare parts, and servicing typically included in the OEMs' offering?

The following gives a sense of the questions that were posed to project developers:

- What insights have you gathered from electrolyzer procurement and operation?
- Are there specific issues in procurement and installation you want to highlight?
- What are the key criteria you consider when selecting an electrolyzer technology and make?
- Could you indicate whether the project has secured a power purchase agreement and confirm the status of grid access arrangements?
- Please describe the project's ownership and governance structure, including the number of participating entities, their respective equity shares, and whether the project is structured as a joint venture.
- Since when is the project operational or what is the anticipated timeline for reaching final investment decision?
- Is the electrolyzer an element that is considered in the financing discussions?

Responses to the questions above were anonymized, consolidated, and systematically analyzed by the authors. The resulting insights were synthesized to extract key findings that inform and underpin the analysis presented in this report.

The third step assesses whether suppliers' equipment and services offerings are sufficiently diverse, robust, and reliable. It evaluates quality assurance, after-sales service, warranties, and long-term support for the offerings—factors that materially influence bankability and operational performance (chapter 4).

Finally, policy and regulatory considerations—such as local content requirements, import restrictions, and permitting conditions—may shape the final procurement decision. This integrated approach ensures that electrolyzer selection aligns with technical needs, economic viability, supplier capability, and the broader enabling framework.

Structure of the Report

The four chapters that follow—chapters 1 through 4—are each devoted to a specific dimension of electrolyzer project evaluation.

Market and technology status. Chapter 1 examines the status of the four main electrolyzer technologies—alkaline (ALK), proton exchange membrane (PEM), solid oxide electrolyzer cell (SOEC), and anion exchange membrane (AEM)—highlighting maturity, operational characteristics, modularity, lifespan, efficiency, integration with renewables, standards, and logistical considerations. It outlines the scope and system boundaries of electrolysis plants, covering the stack, balance of stack (BoS), balance of plant (BoP), and installation.

Price and cost. CAPEX and OPEX are described in chapter 2. The discussion differentiates direct and indirect costs; compares CAPEX across technologies and regions based on project data and literature; and considers contingencies, electricity procurement strategies, operation and maintenance, and water treatment. All these elements together reveal the drivers of the LCOH.

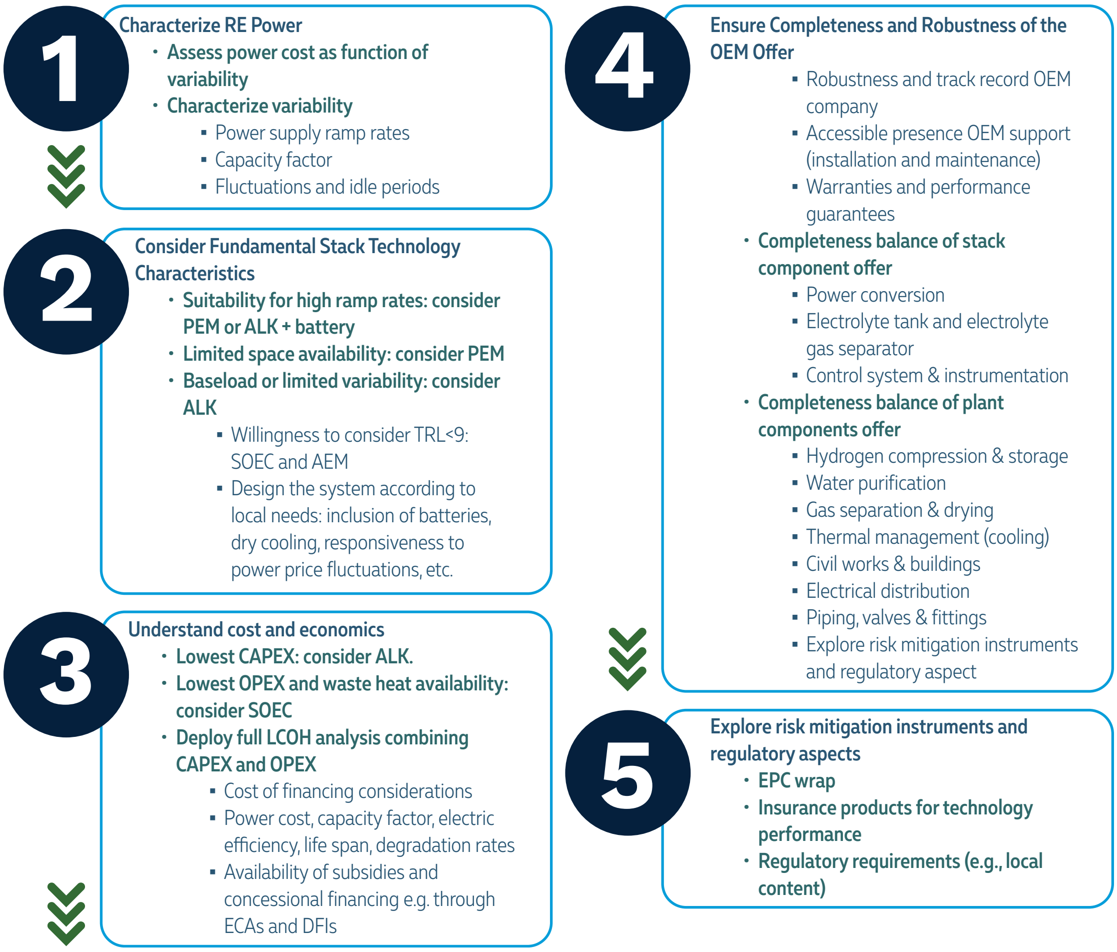
Pathways to reduce cost. Chapter 3 explores innovation and risk-mitigation levers. It also examines advances in materials, manufacturing methods, and system integration, factors that can drive cost reductions and other financial aspects, such as cost of capital. This chapter offers a forward-looking perspective on how technology and finance can converge to make renewable hydrogen more competitive in the coming years.

Commercial offer. The commercial and contractual dimensions of electrolyzer procurement are detailed in chapter 4. The focus is on the structure, scope, and risk allocation mechanisms embedded in procurement models, long-term service agreements, and warranty provisions. The chapter also reviews the operational track records of OEMs, including reliability metrics, technology maturity, and after-sales service. By consolidating primary data and insights from OEMs, this chapter provides developers, lenders, and investors with the commercial parameters they need to evaluate and compare supplier bids.

The report does not advocate a single best technology or solution. Instead, it equips stakeholders in EMDCs with the knowledge to assess, select, and structure renewable hydrogen projects with site- and market-specific financial realities.

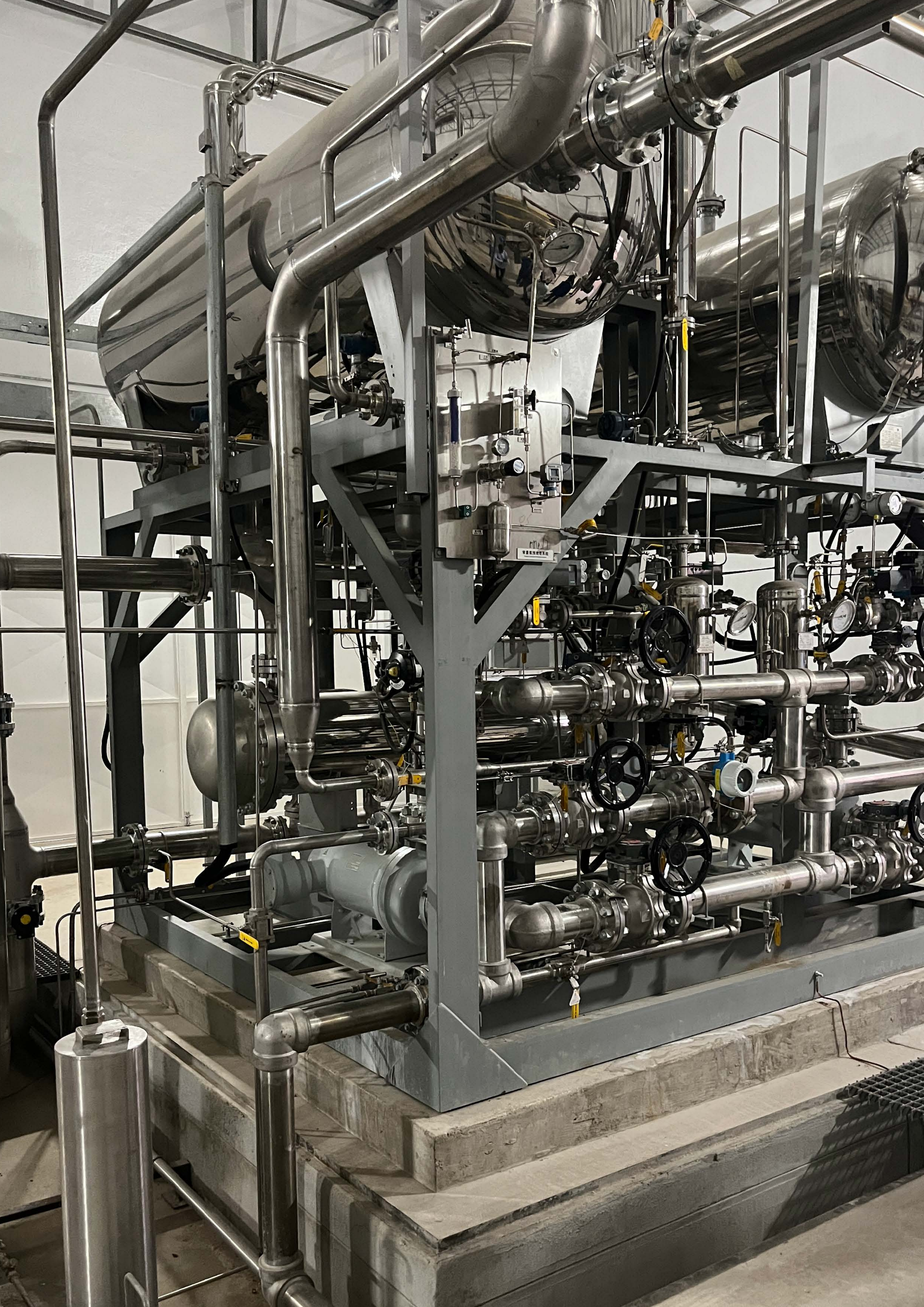
FIGURE AR.1

Electrolyzer selection methodology



Source: World Bank staff analysis.

Note: AEM = anion exchange membrane; ALK = alkaline; CAPEX = capital expenditure; DFI = development finance institution; ECA = export credit agency; EPC = engineering, procurement, and construction; LCOH = levelized cost of hydrogen; OEM = original equipment manufacturer; OPEX = operational expenditure; PEM = proton exchange membrane; RE = renewable energy; SOEC = solid oxide electrolyzer cell; TRL = technology readiness level.



I. Market and Technology Status

Key Points

- As of July 2025, approximately 2.15 GW of electrolyzer capacity was operational worldwide, producing only 0.2 percent of the global annual hydrogen demand. The total figure rises to nearly 20 GW when including projects under construction or at the final investment decision (FID) stage. Although capacity is growing increasingly more rapidly, this still represents an early stage of market development.
- The global market is currently dominated by alkaline (ALK) and proton exchange membrane (PEM) technologies. Of the installed electrolysis capacity, 64 percent utilize ALK systems, while 36 percent rely on PEM systems. Among under-construction projects with a known technology supplier, 84 percent involve ALK systems and 11 percent involve PEM systems, underscoring ALK's continued cost advantage and manufacturing maturity. Meanwhile, solid oxide electrolyzer cell (SOEC) and anion exchange membrane (AEM) systems remain at early demonstration stages.
- As they stand, project pipelines suggest that less than 100 GW of electrolyzer capacity will likely be operational by 2030. This is well below projections, which exceed 150 GW, reflecting hurdles in financing, permitting, and offtake contracting.
- Global electrolyzer manufacturing capacity now stands at 61 GW per year, with an additional 16 GW under construction. Of this total, 43 GW per year (about 70 percent) is dedicated to ALK technology and 13 GW (or 21 percent) to PEM. The sector is experiencing significant overcapacity, prompting consolidation and restructuring among manufacturers as demand lags initial expansion forecasts.
- Each technology exhibits distinct trade-offs in capital expenditure (CAPEX), efficiency, operational flexibility, degradation rate, and technology readiness level (TRL). Project-specific factors, including renewable power profile, load variability, end-use requirements, and water quality, determine the optimal choice. As such, no single electrolyzer type can be considered universally superior.
- Despite technological progress, commercial-scale, continuous operation of electrolyzer equipment over multiyear horizons remains limited. This constrains the ability of

developers and financiers to accurately assess long-term reliability, degradation behavior, and maintenance needs, especially under diverse climatic and grid conditions in emerging markets and developing countries (EMDCs).

- An electrolysis system has three key components: the stack; the balance of stack (BoS), including gas separation, rectification, and cooling systems; and the balance of plant (BoP), which covers water treatment, compression, storage, and control systems. An understanding of cost allocation across these three components forms the basis for technical design and financial modeling.
- Two critical design variables are stack size and module configuration, which influence system cost, plant complexity, logistics, and maintenance flexibility. Industry trends favor modular systems integrating multiple stacks per module for scalability and redundancy. Plants are now being designed as arrays of standardized modules to ease installation, operation, and maintenance.

Hydrogen Demand

The demand for hydrogen and its derivatives is prompted by their many industrial uses. As a versatile feedstock, molecular hydrogen has been pivotal across sectors. In oil refining, it enables hydrocracking and desulfurization—processes essential for producing relatively cleaner fuels such as motor spirit and diesel. In the food industry, hydrogenation stabilizes fats and supports the production of widely consumed items like margarine and butter spreads.

In manufacturing, hydrogen supports advanced metal alloying, precision welding, and defect-free flat glass production. It is also indispensable in electronics, where it helps in the fabrication of semiconductors, light-emitting diodes, and photovoltaic (PV) components. In the medical sector, hydrogen supports the synthesis of critical compounds such as hydrogen peroxide.

Hydrogen's value is further amplified through its key derivatives, ammonia and methanol, which are strategic platform chemicals. Ammonia is central to agriculture and industry, acting as a precursor for nitrogen-based fertilizers, explosives, synthetic fibers, refrigerants, and water treatment agents. Its widespread use supports food security, industrial productivity, and environmental management.

Methanol also supports a range of industrial processes, including the production of formaldehyde, acetic acid, plastics, paints, adhesives, and solvents. Also noteworthy, ammonia and methanol are both emerging as enablers of the global transition to clean energy. They are increasingly recognized as hydrogen carriers and low-carbon fuels for marine transport, automotive applications, and fuel cell technologies.

Global hydrogen demand reached nearly 100 million tons (Mt) in 2024. This global demand reflected continued reliance on hydrogen across refining, fertilizers, and chemicals (IEA 2025).

Output of dedicated renewable hydrogen projects expanded rapidly. They grew 60 percent year-on-year in 2024, surpassing 100 kilotons (kt), equivalent to about 0.1 percent of the total global production. Renewable hydrogen production capacity remains concentrated in China, followed by Europe and the Middle East. New capacity is emerging in India, Africa, and Latin America.

Electrolyzer Demand

As of mid-2025, approximately 20 GW of electrolyzer projects were operational, under construction, or at the FID stage. According to S&P Global, operational capacity stands at 2.18 GW—30 percent growth over 2024 and a ninefold increase since 2020, at a compound annual rate of around 55 percent (Figure 1.1). The electrolyzer market is currently dominated by two mature technologies, ALK and PEM, which account for 64 percent and 36 percent of installed capacity, respectively. Emerging technologies, such as SOEC and AEM systems, represent a small but growing share. China leads global electrolyzer deployment. It hosts 56 percent of the installed capacity. The demand for electrolyzers in China is strongly correlated with the country's action to tender over 1 GW of electrolysis capacity every month, scheduled for 12–14 GW annually (S&P 2025a). This rapid expansion makes China the main driver of the technology's scale-up, setting the pace for global deployment. Europe and the United States follow with 20 percent and 7 percent of installed capacity, respectively (S&P 2025a).

For projects under construction, total capacity is estimated at 15.8 GW; 3.1 GW of projects are not disclosing their technology choice. Among the remaining 12.7 GW, 84 percent are ALK systems, 11 percent PEM systems, and 0.5 GW are hybrid ALK+PEM systems (Figure 1.2). China also leads in construction, at about 53 percent of capacity. The Middle East accounts for 16 percent of construction activity, due to large-scale initiatives like the NEOM project. It is followed by Europe (11 percent) and the United States (3 percent) (S&P 2025a).

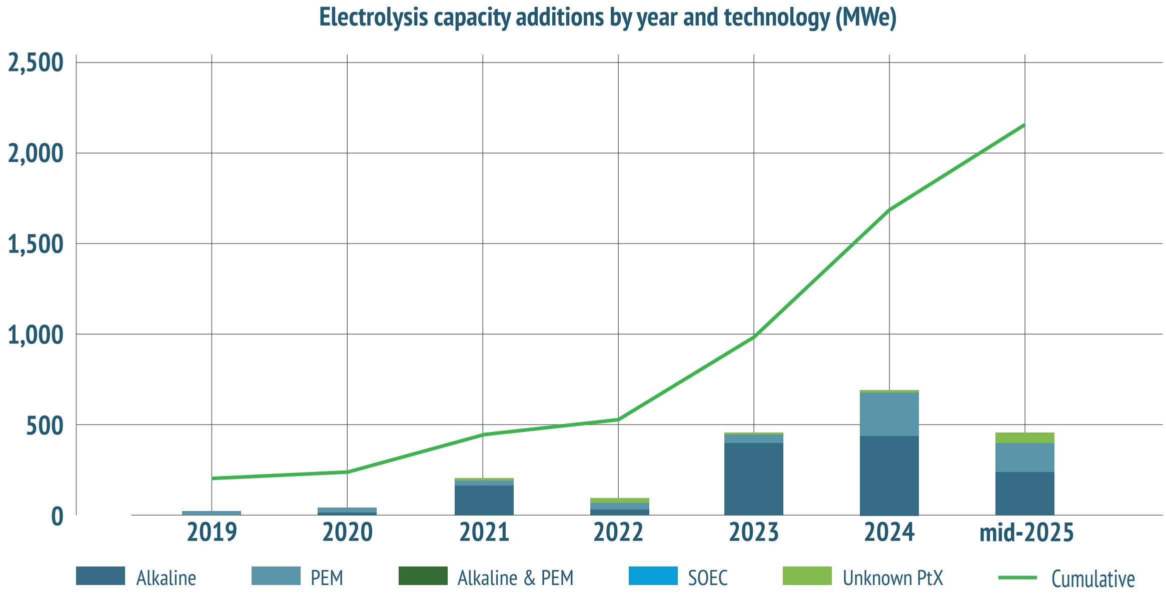
Project sizes are scaling rapidly, with 52 percent of capacity under construction in the 100–500 megawatt (MW) range, leaving only 9 percent below 100 MW (S&P 2025a). These large-scale facilities typically consist of hundreds of modular stacks, which enable better performance optimization and integration with variable renewable energy (VRE) sources.

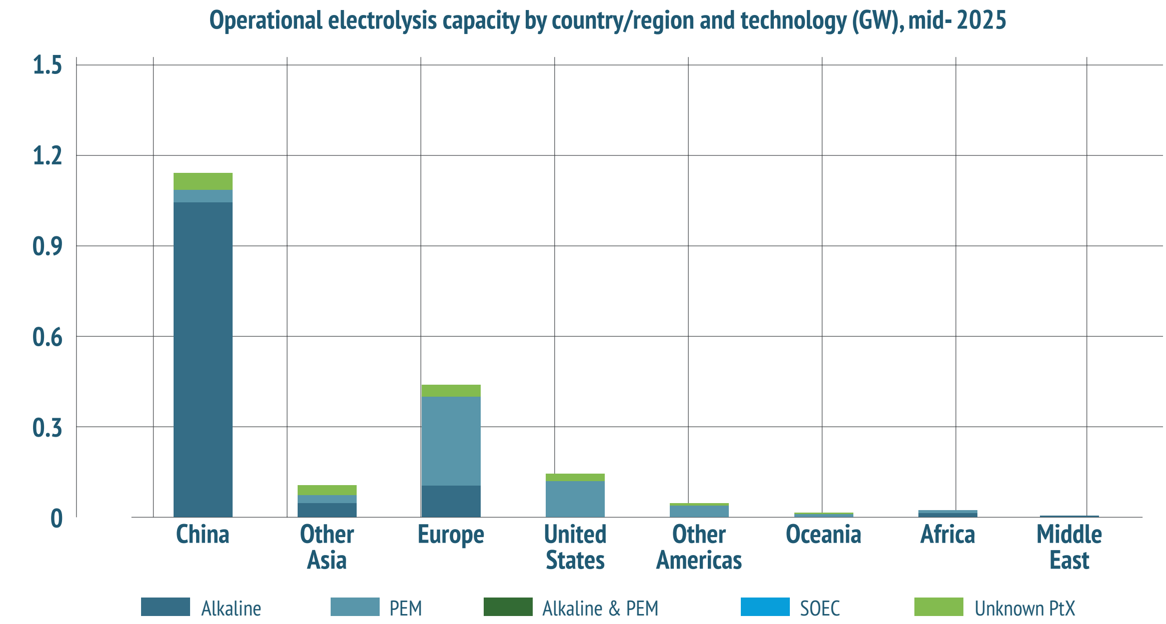
In terms of offtake, incumbent industries dominate early-mover projects between now and 2030: among those disclosing end use, chemicals (primarily ammonia) account for roughly 42 percent, e-fuels for shipping and aviation 7 percent, and refining for 5 percent (S&P 2025a). Each application imposes distinct technical requirements on electrolyzers, such as operating pressure, load flexibility, and integration with thermal or chemical processes. For instance, SOEC systems can leverage waste heat from ammonia or steel plants to improve energy efficiency, while PEM systems are preferred in dynamic environments requiring rapid load response.

But markets keep changing fast. For example, current thinking is that upgrading biotransportation fuels requires a lot of hydrogen—and also an early market opportunity. For example, bioethanol can be converted into sustainable aviation fuel (SAF) through the alcohol-to-jet (AtJ) pathway. The resulting product is upgraded with hydrogen to meet aviation fuel specifications and can be blended with conventional jet fuel as a drop-in SAF (IEA Bioenergy 2025). This is relevant as the decarbonization of the international aviation sector would need SAF from both biofuels and hydrogen synthetic fuels pathways to meet an estimated global demand between 200 and 800 million cubic meters (m3) of SAF (150–650 Mt) by 2050 (EPE 2025).

FIGURE 1.1

Cumulative electrolyzer capacity and annual installations between 2019 and July 2025





Source: S&P 2025a.

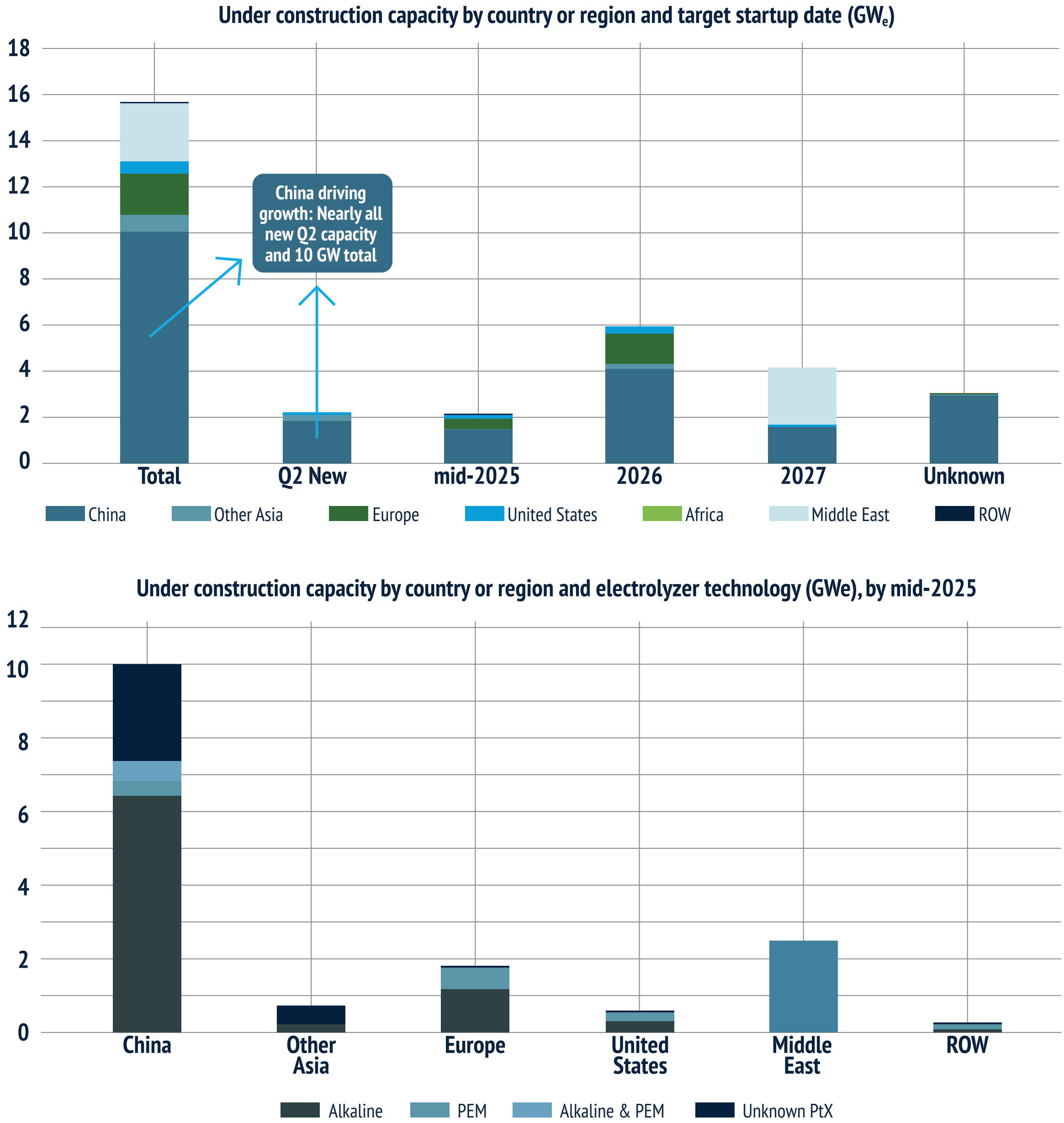
Note: The following are annotations on the original charts:

- *Year-to-date installations of 456 MW are at pace for 32 percent year-on-year growth but short of the 1.75 GW projection.*
- *Second-half installations outpaced first-half installations in 2023 and 2024, due in large part to year-end incentives in China.*
- *A large majority of alkaline capacity is in China, but first-of-a-kind deployments are in the rest of Asia, Africa, and the Middle East.*
- *PEM accounts for 36 percent (162 MW) of capacity, mostly in Europe, but roughly 40 MW are installed in both the United States and China.*

GW = gigawatt; MWe = megawatt electrical; PEM = proton exchange membrane; PtX = Power-to-X; SOEC = solid oxide electrolyzer cell.

FIGURE 1.2

Electrolyzer capacity under construction, April 2025



Source: S&P Global Commodity Insights.

Note: GW = gigawatt; GWe = gigawatt electrical; PEM = proton exchange membrane; Q2 = second quarter; ROW = rest of world; PtX = Power-to-X.

Electrolyzer Supply as of mid-2025

Global electrolyzer manufacturing capacity surged from 2.6 GW in 2020 to 61 GW in July 2025 (S&P 2025a), signaling rapid industrialization. ALK is the most widely manufactured technology. It accounted for 43 GW of installed manufacturing capacity in July 2025 (Figure 1.3). PEM production capacity grew from 510 MW in 2020 to 13 GW in 2025. SOEC and AEM are emerging technologies but represent only a small share of the total installed manufacturing capacity. Only 2.6 GW and 75 MW of annual SOEC and AEM manufacturing capacity, respectively, is operational.

From a regional perspective, Asia and Europe lead in total manufacturing capacity, followed by North America. Capacity is the largest and fastest growing in China, which hosts 36.7 GW of ALK capacity. The country also has some capacity for PEM electrolyzer manufacturing, of 1.3 GW, as well as for all technologies, including 100 MW for SOEC systems and 50 MW for AEM systems (S&P 2025a). India is emerging as a player in electrolyzer manufacturing. It reports 2 GW of manufacturing capacity for PEM systems, 240 MW for ALK systems, and 50 MW for SOEC systems (S&P 2025a). Europe has 5.7 GW of ALK manufacturing capacity and leads in PEM manufacturing capacity, with 7.1 GW. It is also a player in AEM systems, with 25 MW of capacity, and recently inaugurated a 0.5 GW SOEC manufacturing facility. The leader in SOEC system manufacturing, the United States, has 2.5 GW of capacity. It has 1.7 GW of capacity for PEM systems, and some capacity for ALK system manufacturing (S&P 2025a).

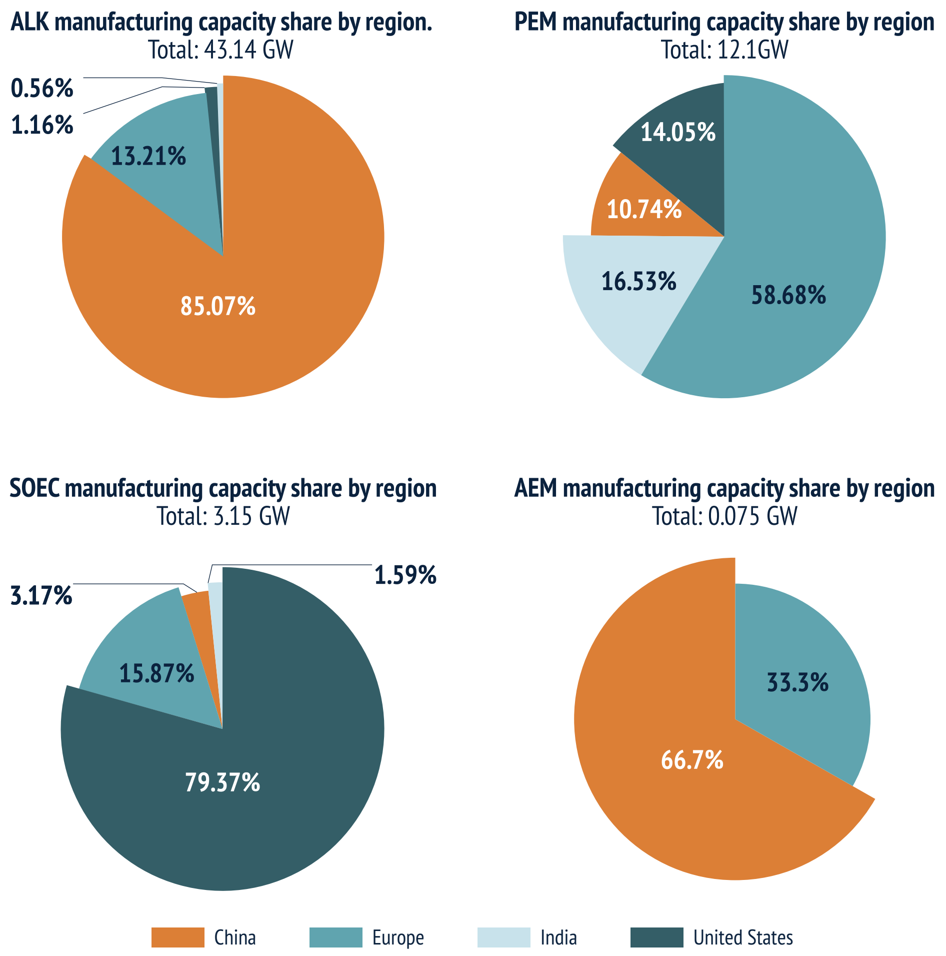
The global ALK electrolyzer manufacturing capacity is highly concentrated. Of the 12 largest manufacturing facilities, 11 are in China and only 1 is in Europe. By manufacturing capacity, the top 10 electrolyzer companies are based in China: Peric (6.5 GW), Elion (5 GW), LONGi (3.5 GW), Sungrow (3 GW), Guofu (2.5 GW), Trina (2GW), Tianjin Mainland (1.6 GW), John Cockerill (1 GW), Qing Qiji (1.5 GW), and Sany (1.5 GW). Outside China, thyssenkrupp nucera and Nel have large ALK electrolyzer system manufacturing facilities in Germany (1.5 GW) and Norway (1 GW) (S&P 2025a; information from original equipment manufacturer [OEMs]).

The global PEM electrolyzer production capacity is concentrated in Europe, which is followed by India, the United States, Australia, and China. The largest PEM electrolyzer system manufacturers are Siemens Energy (3 GW) in Germany, followed by Ohmium (2 GW) in India, Fortescue (2 GW) in Australia, ITM Power (900 MW) in the United Kingdom, and Cummins, which has manufacturing facilities in China (700 MW), the United States (700 MW), and Spain (500 MW). In March 2025, Bosch announced that it was starting the production of Hybrion PEM electrolysis stacks in Bamberg, Germany. Nel has expanded its Wallingford PEM manufacturing facility to 0.5 GW annual capacity; information from OEMs).

It is important to note that the location of a company's manufacturing facilities does not indicate the firm's country of origin. For instance, De Nora has headquarters in Italy, while sites for its manufacturing operations are distributed globally, in Brazil, China, Germany, Italy, India, Japan, and the United States—15 in total. Similarly, Cummins is headquartered in the United States but has manufacturing sites in Belgium, Canada, China, and Spain, as well as the United States.

FIGURE 1.3

Electrolyzer manufacturing capacity share, by region and technology, as of July 2025

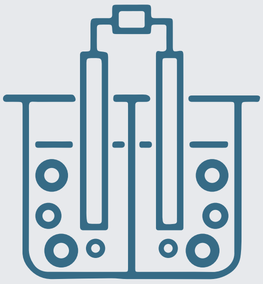


Source: Based on S&P 2025a.

Note: AEM = anion exchange membrane; ALK = alkaline; GW = gigawatt; PEM = proton exchange membrane; SOEC = solid oxide electrolyzer cell.

BOX 1.1

DEMAND FOR AND THE COST OF KEY MATERIALS FOR MANUFACTURING ELECTROLYZERS



Different types of electrolyzers are manufactured with different types of materials. Some of these materials may influence costs and create supply constraints. Some electrolyzers use platinum group metals (PGMs), a group of six chemically similar metals (including platinum, palladium, and iridium) valued for their catalytic and high-temperature performance. Others use rare earth elements (REEs), which are 17 chemically related elements (including lanthanum and yttrium) possessing unique magnetic, optical, and catalytic properties. REEs are processed only in a few countries. Table B1.1.1 shows what key materials are used for manufacturing alkaline (ALK), proton exchange membrane (PEM), and solid oxide electrolyzer cell (SOEC) electrolyzers, as well as the estimated quantity of material needed for each gigawatt of electrolyzer capacity. An earlier World Bank report concluded that the overall material footprint of the hydrogen sector is unlikely to cause stress in most materials markets (World Bank 2022).

TABLE B1.1.1

Prices of the PGMs used in PEM electrolyzers

ELECTROLYZER TYPE	KEY MATERIAL	PGM OR REE	ELECTROLYZER MATERIAL REQUIREMENT(TONS/GW)
ALK	Nickel	–	800
	Zirconium	–	100
	Aluminum	–	500
PEM	Platinum	PGM	0.30
	Palladium	PGM	0.30
	Iridium	PGM	0.70
SOEC	Nickel	–	175
	Zirconium	–	40
	Lanthanum	REE	20
	Yttrium	REE	5

Source: Based on the Breakthrough Institute (2024).

Note: ALK = alkaline; GW = gigawatt; PEM = proton exchange membrane; PGM = platinum group metal; REE = rare earth element; SOEC = solid oxide electrolyzer cell.

BOX 1.1 *(CONTINUED)*

Of the different types of electrolyzers, first-generation PEM electrolyzers are the most constrained, based on their use of PGMs and current production rates. The most critical PGM at this moment is iridium, whose global production is now about 8 tons per year. Consumption of 0.7 tons of iridium for each gigawatt of PEM production capacity, using today's technology, would limit manufacturing capacity to roughly 11 GW per year.

Concerning cost implications for PEM electrolyzers, the component cost for the catalyst-coated membrane (CCM) is the most affected by PGM prices. Material costs for the CCM are influenced most significantly by the anode catalyst, which in this case is iridium. Historically, iridium prices have represented a smaller share of the total costs. As such, the high material cost for iridium—$177,000 per kilogram on average in October 2025, up by 25 percent since 2022—is the reason behind the high price of the anode catalyst. Shrinking iridium loadings thus becomes a key way to lower manufactured CCM costs. The prices of the PGMs used by PEM electrolyzers as of October 28, 2025, are shown in table B1.1.2.

TABLE B1.1.2

Prices of the PGMs used in PEM electrolyzers in October 2025

PGM	PRICE ($/KG)
Iridium	177,110
Palladium	51,010
Platinum	56,140
Rhodium	299,830
Ruthenium	33,315

Source: Based on Heraeus (2025).

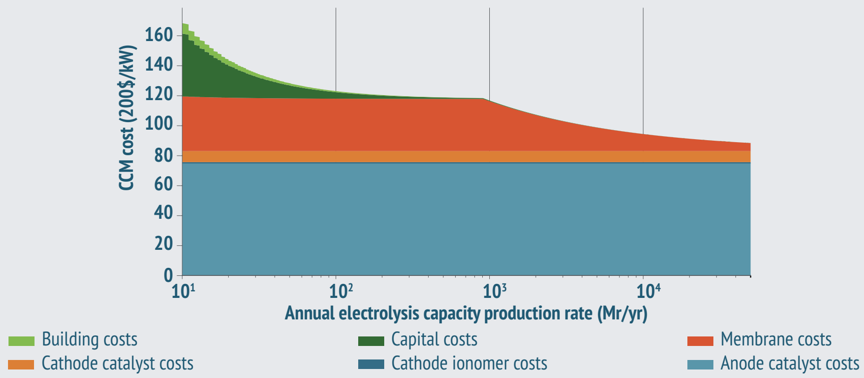
Note: kg = kilogram; PEM = proton exchange membrane; PGM = platinum group metal.

But, as can be seen in Figure B1.1.1, at $80/kilowatt (kW), the cost for PGMs for the CCM still constitutes only a small percentage of the total installed system cost, in the $1,500–2,000/kW range for PEM electrolyzers. Moreover, efforts seek to reduce the catalyst load through different manufacturing technologies and new catalyst formulas. Promising results have been obtained through research and development, but their commercial application still needs to be proven.

BOX 1.1 *(CONTINUED)*

FIGURE B1.1.1

Cost structure for the CCM for PEM electrolyzers



Source: NREL 2024c.

Note: CCM = catalyst-coated membrane; kW = kilowatt; MW = megawatt.

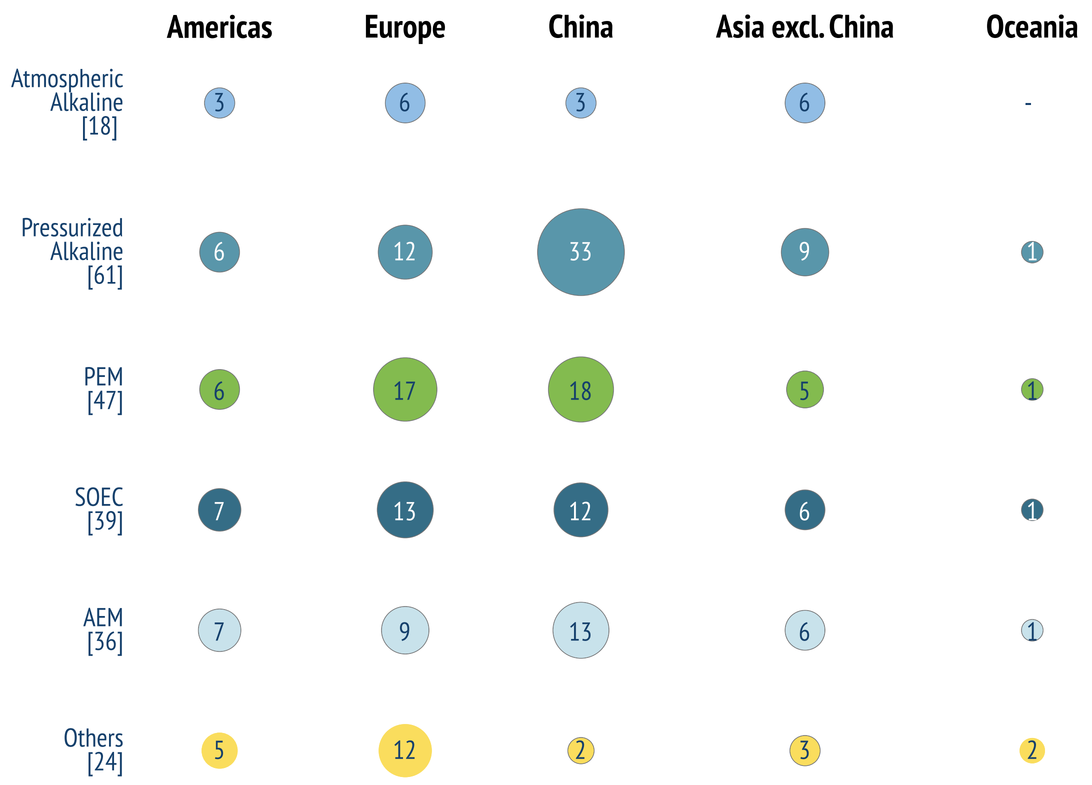
The material implications surrounding SOEC electrolyzers are complex. The reason is this technology requires REEs, which are processed mostly in China, and the government needs to approve exports, which creates a politically charged supply risk. SOEC electrolyzers require REEs like yttrium and lanthanum, which are typically used to optimize the chemical reactions between the electrolyte and the electrodes. The supply of REEs for SOEC electrolyzers is in principle sufficient, including the supply of the more precious REEs like lanthanum and yttrium. Electrolyzer production, even in case of the rapid expansion of electrolysis capacity, will require under 3 percent of the cumulative production from now to 2050.

In case electrolyzers are combined with batteries, the latter can also require lithium and other critical materials. But the batteries for electrolyzers constitute a negligible fraction of overall battery manufacturing across the world.

The electrolyzer industry anticipates expansion despite the present imbalance between manufacturing capacity and market demand (Figure 1.4). As of July 2025, 19 new manufacturing facilities were under construction worldwide, with additional capacity of up to 16 GW expected to come online within the next two years. The largest projects are in China, which accounts for 7.9 GW of new capacity, followed by the United States with 2.7 GW, Europe with 1.6 GW, and Japan with 1 GW (S&P 2025a).

FIGURE 1.4

A snapshot of electrolyzer manufacturers around the world



Source: Based on the VNZ Electrolyzer Original Equipment Manufacturer Landscape Database, adjusted based on stakeholders' inputs.

Note: AEM = anion exchange membrane; PEM = proton exchange membrane; SOEC = solid oxide electrolyzer cell.

The electrolyzer sector is being restructured, and several companies are facing bankruptcy or exiting the market altogether. These changes mean the manufacturing landscape will likely be transformed in the coming months and years. Modern manufacturing plants are now implementing significant automation as a way to reduce costs while maintaining quality and supply. Furthermore, some companies maintain full control over their supply chains, while others source key components externally. Notably, constraints in the availability of components such as transformers mean that the true manufacturing capacity for complete electrolyzer systems may be lower than assembly statistics suggest. Across the industry, order books remain underfilled, reflecting the gap between production capacity and market demand.

Electrolyzer Technologies and Technology/ Commercial Readiness Levels

Electrolyzers are a core technology enabling the production of hydrogen through splitting
Electrolyzers are a core technology enabling the production of hydrogen through splitting water molecules into hydrogen and oxygen using electricity. Multiple electrolyzer technologies exist, each with distinct technical characteristics, maturity levels, and applications. This report focuses on the four leading types of electrolyzer technologies now shaping global deployment: ALK, PEM, SOEC, and AEM.

Before delving into the technologies, it is essential to emphasize that there is no single universally best electrolyzer option. The optimal choice relies on the project and is shaped by factors from the operational profile to the required purity of feedstock, to opportunities for thermal integration, to the nature and variability of the renewable power supply. Before choosing an option, all options should be weighed, narrowing down to the one that aligns with the project's technical, economic, and environmental objectives, thus ensuring the most effective and sustainable hydrogen production pathway.

A commonly used indicator to assess technology maturity is the TRL, introduced by the National Aeronautics and Space Administration (NASA). This nine-level scale ranges from basic principles observed (TRL 1) to full commercial deployment (TRL 9). The entire journey—from concept validation through to prototyping, testing in relevant environments, and regulatory approval—is captured in turn. TRLs are a valuable framework for guiding technology selection, monitoring progress, and evaluating readiness for market integration.

The maturity of electrolyzer technologies is typically expressed in TRL. ALK, the most established electrolyzer technology, is nearing full commercialization (TRLs 8–9). Supported by over a century of operational experience, it is now deployed in chemical industries and used in renewable hydrogen projects. The PEM technology is also at TRLs 8–9, with commercially available multi-megawatt systems and expanding manufacturing capacity. SOECs are progressing through TRLs 6–8 and are now in the demonstration and pilot phases. AEM, a newer entrant, has reached TRLs 5–8, with pilot-scale implementations underway (Sebbahi et al. 2024). The TRLs do not capture the variation in technology within these four categories or the maturity of technology scaling up from megawatt to gigawatt, or the flexible operational practices.

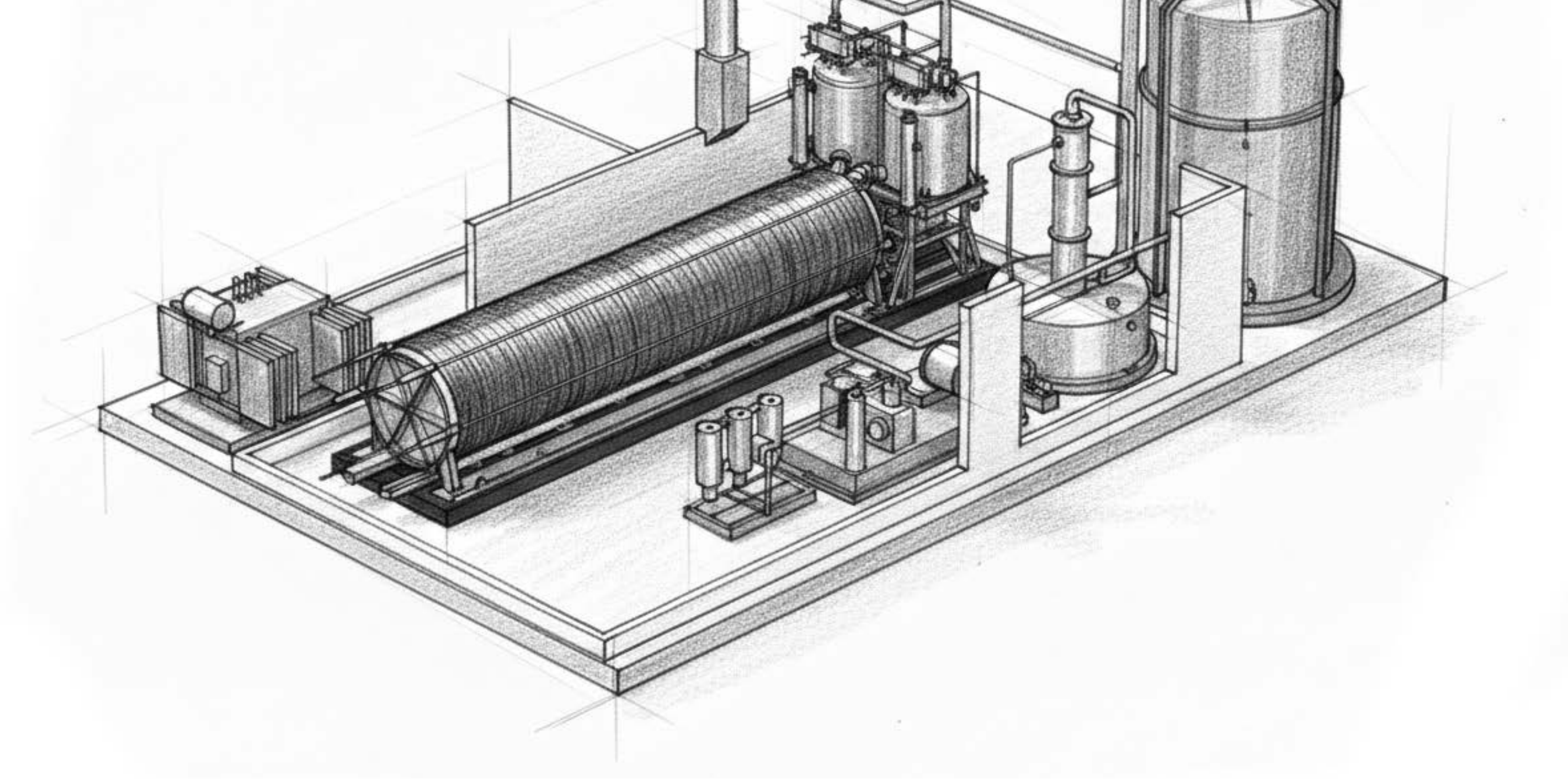
Commercial readiness levels (CRLs) complement the conventional TRL framework by assessing whether a technology is not just proven but also commercially viable. While TRLs measure technological maturity, from laboratory validation to full-scale operational demonstration, CRLs assess both market maturity— including competitiveness, bankability, and supply chain robustness—and the ability to deploy at scale (ARENA 2014). Technology may reach high TRLs but remain commercially unready if business models are unproven, costs remain high, or investment risks are unresolved.

Although a widely accepted CRL assessment for hydrogen electrolyzers currently does not exist, deployment levels, supply chain maturity, investor confidence, and project financing trends can help reach a reasonable approximation. ALK electrolysis, now exceeding 1 GW of installed capacity and supported by multiple global OEMs, and deployed across diverse market segments, can be positioned between CRL 4 ("multiple commercial applications becoming evident, though still policy supported") and CRL 5 ("market competition driving broader deployment under stable long-term policy frameworks").

PEM technology, with close to 1 GW deployed globally but concentrated in Europe and supplied by fewer manufacturers, fits between CRL 3 ("commercial scale-up enabled by targeted policy support and early debt financing") and CRL 4.

By contrast, SOEC and AEM technologies remain at an early commercialization stage, with only pilot and first-of-a-kind plants operating. Their maturity aligns with CRLs 2–3, corresponding to "commercial trial" and "early commercial scale-up," respectively—reflecting limited operational data, higher technology risk, and emerging supply chains.

Beyond the TRL and CRL indicators, it is important to have a solid understanding of the operating principles underlying each technology, given their cost and performance profiles, as further discussed in this report.



Alkaline (ALK) Electrolyzers

ALK is the dominant and most commercially mature technology for the production of renewable hydrogen. As of mid-2025, over 7.5 GW of ALK capacity were in operation or under construction globally. Developers can choose between atmospheric and pressurized designs for ALK electrolyzers, each with trade-offs in compression and flexibility. ALK electrolyzers offer cost advantages, due to the use of abundant materials and durable diaphragms, but face design limits at high pressures (limiting operation with certain profiles of VRE power supply), and are operated at lower current densities than PEM electrolyzers (resulting in larger machines for the same production capacity). Ongoing research and development (R&D) in membranes, catalysts, structures, and control systems is increasing electricity efficiency, lowering costs, and enhancing bankability. ALK is a competitive option for renewable hydrogen projects. Also, experience around the integration of electrolyzers into plants is growing, for example, as is knowledge on how the use of batteries can facilitate the integration of ALK electrolyzers with VRE. Combinations of ALK and PEM technologies have been deployed in some recent plants for the same purpose. It should be noted that ALK electrolyzer designs vary in pressure and current density, as well as controls at the cell or stack level. While most Chinese electrolyzers originate from the same design (pressurized stack), other manufacturers have chosen different pathways. As such, these specification details need to be considered when offers are compared.

Overview

First deployed at industrial scale in the early 20th century to supply hydrogen for fertilizer production, ALK has since evolved into the most used technology in the electrolyzer market. Today, some of the world's largest renewable hydrogen projects are being built with ALK electrolyzers, and they show how this technology is being deployed at scale.

The most prominent example is the NEOM project in Saudi Arabia, where thyssenkrupp nucera is supplying over 2 GW of electrolysis units to produce hydrogen, which will be converted into ammonia for export. The project is scheduled to come onstream at the end of 2026. Envision's 500 MW Chifeng project in China, operational since 2025, is the world's largest off-grid renewable hydrogen and ammonia facility. It combines atmospheric ALK and PEM technologies, is renewables powered, incorporates artificial intelligence, and integrates battery storage (Envision 2025). Expansion plans aim for 2.5 GW by 2028, supported by global offtake agreements, including with Marubeni.

Also in China, Sinopec's Ordos project in Inner Mongolia is progressing through commissioning. The project is designed to produce 30,000 tons of hydrogen annually using nearly 390 MW of electrolysis powered by dedicated wind and solar. The hydrogen produced will feed a nearby coal-chemical complex to reduce emissions (Sinopec 2025). The project, backed by an investment of approximately $830 million, includes substantial onsite storage. Meanwhile, Sinopec's Kuqa project in Xinjiang, operational since 2023, runs 260 MW of ALK systems from Chinese OEMs such as Cockerill Jingli, LONGi, and Peric. The project supplies hydrogen for refinery operations and pilot grid blending. Early operational data have provided valuable insights into system performance.

In Europe, Stegra in Sweden is installing over 700 MW of ALK electrolyzers—also from thyssenkrupp nucera—to produce hydrogen for the production of direct reduced iron in its green steel plant (Stegra 2025). The electrolyzers were installed over the course of 2025, marking a milestone in industrial decarbonization.

Technology Basis

ALK electrolyzers employ a liquid alkaline solution, typically potassium hydroxide, as the electrolyte to facilitate ionic conductivity across the cell. Within the cell, oxygen is generated at the anode and hydrogen is generated at the cathode, which are separated by a porous diaphragm saturated with the electrolyte. ALK operates at moderate temperatures (60–80°C) and relies on nonprecious metal electrodes such as nickel. The electrolyzers feature simplicity (due to their reliance on nonprecious metal electrodes), durability, and cost-effectiveness rooted in decades of industrial deployment (IRENA 2020).

Atmospheric vs. pressurized designs. ALK electrolyzers are typically manufactured in two configurations: atmospheric and pressurized. Atmospheric electrolyzers operate at 1–2 bar and require additional hydrogen compression for downstream applications. Pressurized systems deliver hydrogen at 15–20 bar, reducing downstream compression needs and associated BoP costs (IRENA 2020). European OEMs like thyssenkrupp nucera and Nel predominantly offer atmospheric designs, while Chinese manufacturers like Peric and LONGi predominantly offer pressurized configurations.

Low- vs. high-current designs. ALK electrolyzers can also be grouped into two categories based on current density—low and high. Current density is a measure of productivity per unit of cell area. Low-current-density (LCD) units operate at around 0.2–0.4 amperes per square centimeter (A/cm^2)

and rely on nickel-based catalysts (e.g., Raney nickel [Ni], nickel-iron [Ni-Fe] oxides) and porous polymer ceramic separators (e.g., Zirfon) (Sebbahi et al. 2024; Zhao et al. 2025; Agfa 2024; AEA 2023). LCD designs benefit from low-cost materials, proven durability, and modest maintenance requirements, making them attractive for applications prioritizing reliability over compactness. They require larger electrode areas, however, and more extensive BoP infrastructure, which can drive up CAPEX.

By contrast, high-current-density (HCD) ALK electrolyzers achieve current density of 0.8 up to 2 A/cm^2 in laboratory conditions through zero-gap designs, thinner membranes, and advanced catalysts adapted from the chlor-alkali industry. These designs boost hydrogen output per unit area and volume, improving stack productivity. HCD systems often incorporate platinum- or ruthenium-based coatings, sometimes combined with elements like cerium to enhance reaction kinetics and durability (Zhao et al. 2025). While these enhancements boost performance, they also introduce higher material costs due to reliance on platinum group metals (PGMs). Additionally, the catalysts' sensitivity to impurities, especially iron, necessitates stricter material standards, such as the use of titanium bipolar plates, adding to system complexity and cost.

Flexibility and Operational Limits

Historically, ALK electrolyzer technology has exhibited limited dynamic response and load-following capabilities relative to PEM systems. Conventional pressurized ALK models typically operate within 30 percent to 100 percent of rated load (Advait Group n.d.), making them less adaptable to intermittent renewable energy sources. However, recent advancements in atmospheric designs, such as those from thyssenkrupp nucera and Nel, have pushed the minimum load threshold down to 10 percent. For example, Verdagy's eDynamic® electrolyzers are claimed to operate with a minimum load threshold as low as 5 percent, increasing compatibility with variable renewable power. While individual stacks may still struggle with rapid load changes, plant-level modular operation, where multiple stacks and modules are orchestrated collectively, can improve overall system flexibility. This approach makes partial operation, staggered ramping, and better alignment with power availability possible. Other emerging innovative ALK models, like the Ruggedcell technology of Hydrogen Optimized, are claimed to be able to operate in the entire range from 0 percent to 100 percent, but this needs commercial-scale proof. It is important to note, however, that real-world experience with such dynamic regimes is still limited and the long-term impact on stack durability and performance under frequent cycling remains uncertain.

Costs of Materials and Components

ALK electrolyzers are typically constructed from abundant, low-cost materials such as nickel, steel, and polymer-ceramic diaphragms. This reduces the exposure of CAPEX to price volatility and supply chain constraints. Advanced HCD ALK designs (e.g., Asahi Kasei, DeNora) may incorporate small amounts of precious metals like ruthenium to boost performance, but loadings are minimal compared with PEM designs (AEA 2023). Such designs exclude the use of iron and steel, however, as they poison the catalyst. Therefore, more expensive materials must be used for bipolar plates (e.g., nickel or titanium).

Technological progress in membrane and diaphragm materials has also been pivotal in adding to the durability, efficiency, and economic viability of ALK electrolyzers. Early designs used asbestos diaphragms, which provided chemical stability but suffered from mechanical degradation, high gas permeability, and health-related drawbacks. Environmental and health regulations have meant a phaseout of asbestos. Modern systems rely on polymer-ceramic composites, such as zirconia-reinforced polysulfide (e.g., Zirfon), which offer structural integrity, low resistance growth, and chemical resilience under harsh alkaline conditions. These materials support operational lifetimes from 10,000–90,000 hours depending on system design and load profiles. They also deliver higher hydrogen purity, lower gas crossover rates, and reduced component replacement frequency, minimizing unplanned downtime and improving overall system reliability.

Commercial Stacks and modules

The stack of an ALK electrolyzer is the core unit where electricity drives the splitting of water into hydrogen and oxygen. An ALK electrolyzer module, by contrast, is a larger packaged unit, which integrates the stack with the BoS components required for operation. The key advantage of a module is that certain equipment can be shared across stacks. This reduces overall system costs. Modules are the standard building blocks sold by manufacturers, and are combined to build a full hydrogen plant.

Commercialization of ALK electrolyzers has converged around standardized multi-megawatt stack sizes that build up to larger modular skids (NREL 2025). For instance, John Cockerill Hydrogen has pushed the envelope with a single 5 MW pressurized stack—the largest available designed for integration into modular skids (John Cockerill 2024b). Some Chinese OEMs have also announced even larger single ALK stacks. For example, Mingyang Smart Energy has a stack with a rated hydrogen output of 1,500–2,500 normal cubic meters per hour (Nm^3/h) and Shuangliang has a 5,000 Nm^3/h single stack, which are equivalent to approximately 12 MW and 22 MW stacks, respectively. European manufacturers such as thyssenkrupp nucera offer standardized 20 MW modules, which serve as repeatable building blocks for projects in the range of several hundred megawatts. In China, manufacturers including LONGi and Sungrow are marketing modules in the 5–15 MW range, positioning them as flexible solutions for both small- and large-scale projects.

Despite these advances, scaling up stack size presents technical challenges. Larger stacks face issues such as uneven current distribution, gas crossover, sealing stress, higher overpotentials, and thermal management complexities. These issues can impact efficiency and durability. Oversized stacks and modules may also exceed standard transport dimensions, complicating logistics, testing, and site installation.

The shift toward standardized modules reduces engineering complexity, accelerates deployment timelines, and creates benchmarks that can be adopted across projects and geographies. For investors, the shift to multi-megawatt building blocks has direct financial implications. Standardization supports replicability, procurement certainty, and economies of scale in manufacturing. At the same time, modularity lowers engineering, procurement, and construction (EPC) risks and reduces contingencies in financial models. In addition, modular designs simplify operation and maintenance (O&M) planning, as standardized spare parts, service routines, and warranties can be applied across multiple units.

Pathways Toward Further Improvement

Regarding both performance and cost, ALK electrolyzers offer room for improvement. Traditional systems use nickel electrodes and polymer membranes, which are reliable but consume more electricity at high operating levels due to internal resistance and energy losses. Upgrading to newer materials (e.g., advanced diaphragms and more efficient catalysts) can reduce energy consumption by 5–10 percent. These savings also extend the lifespan of the electrolyzer stacks to more than 90,000 operating hours and reduce the frequency of replacement. Overall operating costs are reduced and the system becomes more reliable in turn (Sebbahi et al. 2024).

Improving the performance of ALK electrolyzers includes more than just utilizing better materials. It can also entail incorporating smarter design and system integration. At the component level, innovations like zero-gap configurations and optimized flow-field designs help manage gas bubbles more efficiently. This reduces internal resistance and boosts energy efficiency. Nel is lowering electricity consumption to under 50 kilowatt-hours per kilogram of hydrogen (kWh/kgH2), and to as low as 47 kWh/kg H2 using direct current (approximately 51 kWh/kgH2 using alternating current), for its pressurized ALK electrolyzer (based on an interview with an OEM). At the system level, the next generation of control platforms will handle dynamic power inputs, especially from variable renewable sources like solar and wind. These platforms can also support predictive safety monitoring and real-time performance optimization, making ALK systems more responsive, safer, and better suited for integration with fluctuating energy supply. Lessons from a long-operating ALK electrolyzer are summarized in Box 1.2.

BOX 1.2

LESSONS FROM CACHIMAYO, THE WORLD'S LONGEST-OPERATING ALKALINE ELECTROLYZER

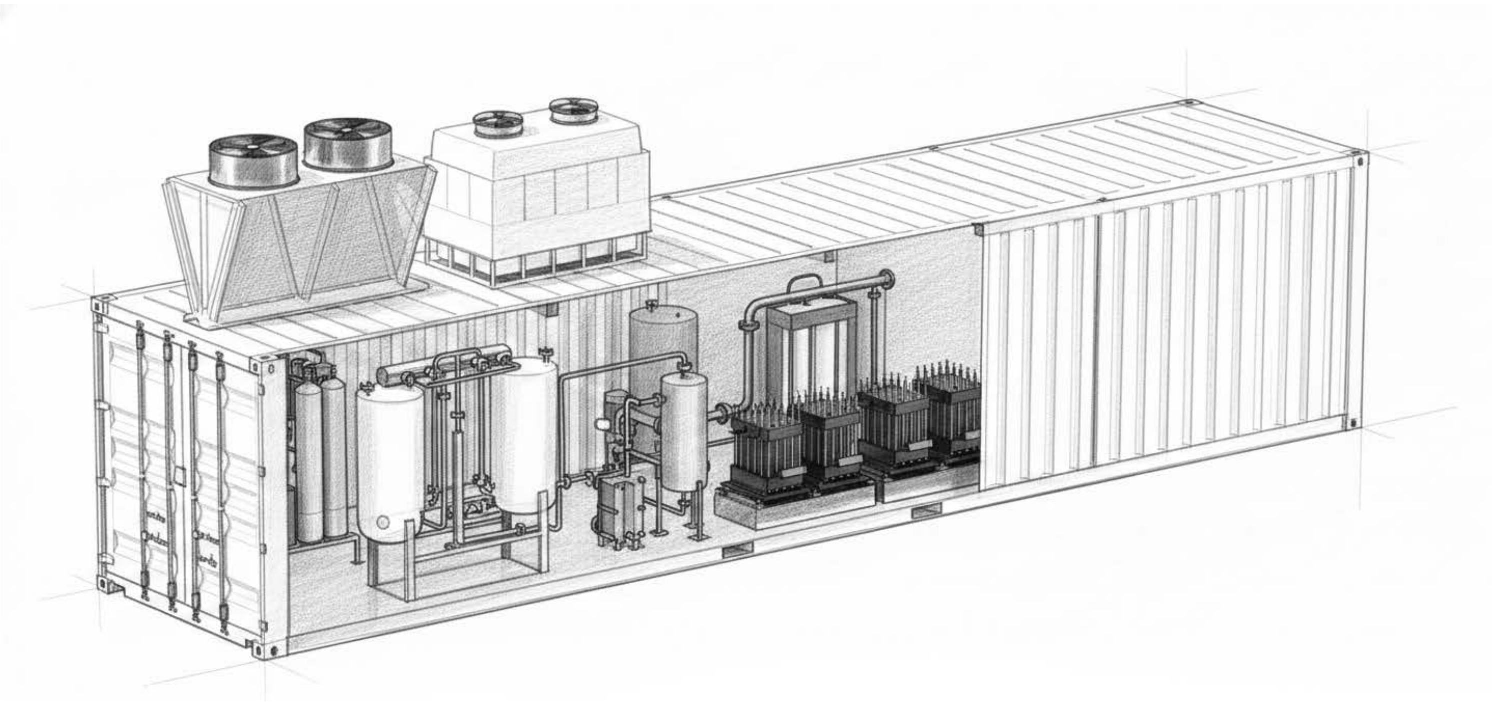
Commercial-scale experience with electrolysis remains limited, but the existing fleet of electrolyzers offers important operational lessons for emerging hydrogen developers. According to the International Energy Agency's global electrolyzer project database, only 87 projects exceeding 5 MW, roughly half of projects between 5 and 10 MW, and half of projects above 10 MW had been operating for at least a year as of 2025. Projects above 100 MW operate exclusively in China—including Shenghong, Ningxia, Da'an, Kuqa, and Chifeng—attesting to the country's accelerated scale-up of low-cost manufacturing of alkaline (ALK) electrolyzers and vertically integrated project deployment.

The only long-lived electrolyzer-based ammonia project is the Cachimayo plant in Peru, which has operated continually since 1965 and remains the world's longest-running commercial green hydrogen facility. The plant currently runs six 5 MW pressurized ALK systems (30 bar), producing 8 tons of green hydrogen per day. The systems are derived from the historical Lurgi design lineage, which is now represented by original equipment manufacturers such as IHT (Switzerland) and Sunfire (Germany). The facility operates on continuous hydropower, which enables round-the-clock performance. Strategic curtailments occur during peak-tariff evening hours.

Operational practices at Cachimayo also yield instructive technical insights. Gas purity is continuously monitored using inline sensors, with automatic venting protocols to maintain quality—an important reminder that real-world hydrogen plants must incorporate redundancy, venting management, and safety margins not captured in simple efficiency specifications. Maintenance focuses on separator performance, electrolyte management, and structural balancing, as static alkaline membranes require long-cycle but predictable refurbishment. Longevity data suggest that alkaline membranes can last from 15 to more than 20 years, with replacement decisions typically triggered by declining product purity (oxygen output often deteriorates first, falling below the 97.5 percent threshold after 160,000 operating hours).

There have been recent additions, including the installation of a new 5 MW Chinese ALK electrolyzer at the site in 2024, but they are too recent for robust technical conclusions. Notably, production at Cachimayo is now constrained mainly by the ammonia synthesis section, which would require substantial investment. Efforts now prioritize sustaining hydrogen output as legacy units reach 15–25 years.

"ALK is the dominant and most commercially mature technology for the production of renewable hydrogen."



Proton Exchange Membrane (PEM) Electrolyzers

PEM electrolysis is gaining momentum: 1.3 GW of capacity is either operational or under construction worldwide. PEM technology uses a solid polymer electrolyte, which facilitates operation at high current densities, and differential pressures, which permit more compact systems and direct compatibility with fluctuating renewable power profiles. Key challenges for PEM electrolyzers include their reliance on scarce iridium catalysts, perfluorosulfonic acid (PFSA)-based membranes, and titanium-intensive hardware. Advances in catalyst design, recycling, alternative membranes, and coated stainless steel components can drive down costs and make the electrolyzers more durable. PEM electrolyzers are deployed now in modular configurations, and as standardized units of 2–20 MW supporting rapid deployment and integration into large-scale hydrogen plants.

Overview

PEM electrolyzers were first explored in the 1960s by NASA and valued for their compactness and efficiency. Through the 1980s–90s, high costs and limited durability slowed deployment. But breakthroughs in membrane chemistry, catalyst development, and system engineering reignited interest in the early 2000s. Over the past decade, declining costs of renewable energy, supportive policy frameworks, and scaling of manufacturing have together propelled PEM electrolysis to commercial viability as a key technology in global hydrogen production.

Technology Basis

PEM electrolyzers operate at 50–80°C and use pure water as feedstock. The core component of these electrolyzers is a solid polymer electrolyte membrane (e.g., Nafion™), which is nonporous and enables high gas purity and facilitates operation at differential pressures (IRENA 2020). This design allows for compact systems with rapid response times and high operational flexibility—ideal for integration with intermittent renewable energy sources. The acidic environment requires, however, precious metal catalysts, primarily platinum and iridium. These drive up capital costs and make the supply chain increasingly sensitive. However, the design enables high current densities, supports compact system configurations that require 5–10 times less electrode area than ALK electrolyzers to achieve equivalent hydrogen output, and delivers rapid load responses. The PEM technology is much more suitable for direct coupling with VRE.

Flexibility and Operational Limits

A major differentiator of PEM technology is its dynamic load response. Systems can operate at as low as 10 percent of nominal load, ramping up within seconds, as against ALK systems, which feature slower response times. These features are crucial for integrating with intermittent renewable power (ITM Power 2024). This makes PEM especially attractive for markets with high shares of solar and wind generation, where operational flexibility directly reduces reliance on grid-firming infrastructure.

Costs of Materials and Components

A defining cost driver for PEM electrolyzers is their reliance on scarce and costly materials, especially within the electrochemical stack. At the anode, PEM stacks require iridium as the oxygen evolution catalyst. The annual supply of one of the rarest elements globally, that of iridium, is estimated at under 10 tons per year (IRENA 2020). The cathode typically uses platinum, while the stack depends on titanium-based porous transport layers and bipolar plates (the direct use of steel can poison the catalyst). This use of precious materials constitutes a major cost component.

Industry and research efforts are therefore focused on reducing precious metal loadings without compromising performance. Innovations in PEM technology are cutting iridium use by as much as 40 percent through nanostructured catalysts, optimized deposition techniques, and advanced membrane electrode assembly designs, without affecting efficiency or durability (Surkus and Pham 2024). In parallel, recycling initiatives are gaining traction. Closed-loop recovery systems show promise for stabilizing long-term availability of iridium and reducing environmental impact. In terms of hardware, research into coated stainless steel and alternative alloys aims to reduce reliance on titanium, further lowering material costs.

A potential concern is the use of PFSA membranes, which face restrictions under Europe's proposed PFSA regulations (ECHA 2025). Reinforced PFSA membranes and PFSA-lean ionomers are under development, but fully PFSA-free options remain at the research stage. Meanwhile, companies such as Electric Hydrogen are promoting life-cycle stewardship frameworks to manage existing PFSA-related materials responsibly while alternatives mature. The US Department of Energy has recycling programs that are bringing large industry groups together to work on alternatives to PFSA-coated membranes.

Commercial Stack and Modules

PEM electrolyzers are based on stacks, core units that electrochemically split water into hydrogen and oxygen. Each stack contains multiple layered cells operating under high current densities and outfitted with solid polymer membranes and precious metal catalysts. These stacks are integrated into modules, which include essential BoS components, such as water purification, power electronics, cooling systems, and gas-handling units.

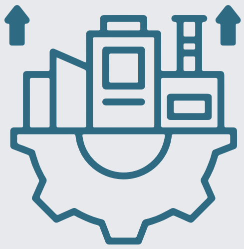
Commercial deployment of PEM electrolyzers has converged around modular systems in the 2–50 MW range, for replication in larger plants. This modular approach enables flexible deployment, streamlined engineering, and accelerated project timelines. Siemens Energy's Elyzer P-300 exemplifies this trend. It integrates 24 stacks into a standardized 20 MW module. Reference projects using Elyzer P-300 reach 100 MW. Similarly, Nel's proton exchange membrane stack module (PSM) combines eight 1.25 MW stacks into a 10 MW module, while Accelera by Cummins offers containerized units of 1–2.5 MW, which scale to 20–90 MW plants. ITM Power markets a plug-and-play 5 MW unit—Neptune V—priced at €5 million and a 50 MW product called ALPHA 50, which is a full-scope plant priced at €50 million: a €1,000/kW stack + BoS (OEM interview). These standardized configurations reflect an industry shift toward repeatable, factory-assembled systems that reduce on-site complexity and support economies of scale in manufacturing and deployment (DOE HFTO 2024; NREL 2025; Siemens Energy 2024).

Pathways Toward Greater Improvements

PEM electrolyzers can be made more efficient through better catalysts, more economic catalyst utilization, better membranes, and water/thermal management systems that reduce energy losses. Durability is being addressed with the development of more robust materials able to resist degradation under frequent start-stop cycles and high current densities. Costs can be brought down by reducing reliance on precious metals, scaling up manufacturing, and standardizing system designs to achieve economies of scale. Together, these efforts seek to make PEM electrolyzers more reliable and affordable for large-scale hydrogen production. Another pathway for further improvement is through manufacturing. As such, recent advances in electrolyzer manufacturing are now focusing more on automation to reduce production costs and scale capacity. With Air Liquide, Siemens Energy has implemented a highly automated and digitally monitored PEM stack production line at its Berlin gigafactory. Robotics, in-line quality control, and manufacturing execution systems have been implemented to lower labor costs, shorten the takt time, and improve first-pass yield (Siemens Energy 2023, 2024a). Fraunhofer Institute for Production Technology has developed roll-to-roll (R2R) membrane electrode assembly coating and continuous bipolar plate fabrication systems for PEM electrolyzers. Coating, drying, lamination, and cutting are integrated in a single line to reduce handling, scrap rates, and manual labor, thereby directly lowering CAPEX (Fraunhofer IPT 2024). Box 1.3 explores reasons behind the increased interest in hybrid ALK and PEM systems.

BOX 1.3

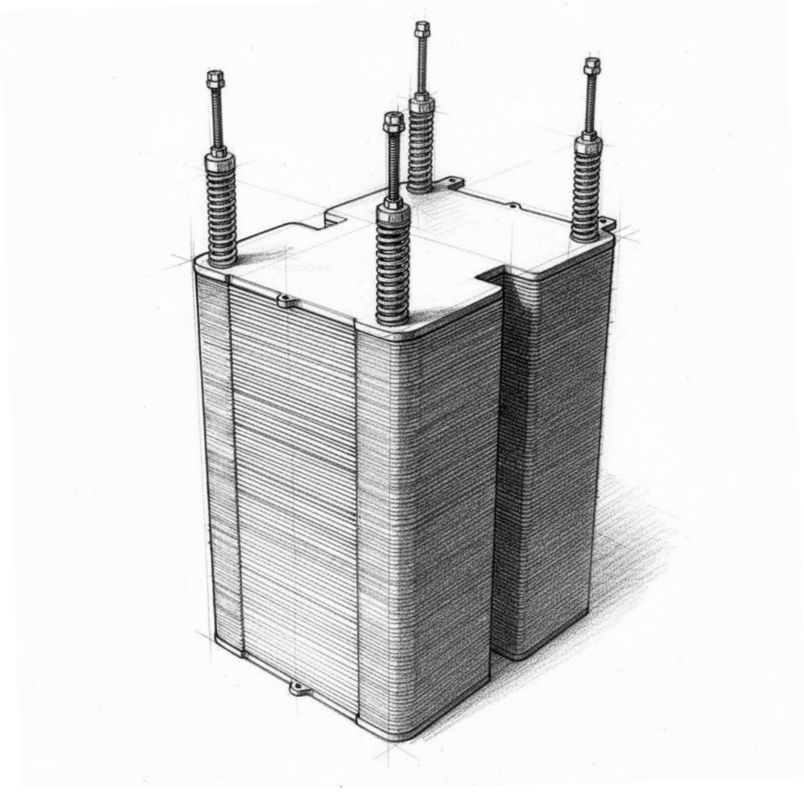
BENEFITS OF HYBRID ALK + PEM SYSTEMS



Alkaline (ALK) and proton exchange membrane (PEM) electrolyzer technologies have various operational characteristics that have sparked interest in hybrid configurations. PEM systems offer faster ramping and lower minimum loads, which is better suited for direct coupling with variable renewable energy. ALK systems, by contrast, offer lower capital expenditure, longer stack lifetimes, and more established supply chains. Combining the technologies would leverage their complementary strengths.

Recent studies highlight the potential benefits of hybridization. Analysis shows that for a 130 kW system powered by hybrid wind–solar photovoltaic, an ALK + PEM configuration has a 10 percent lower levelized cost of hydrogen than an ALK-only system and 20 percent lower than a PEM-only system (Lin 2024). Additional benefits of hybridization have been identified on the power system side (Li et al. 2024), where an ALK + PEM + batteries system is deployed in a wind-dominated microgrid. The analysis shows that, compared with systems without PEM, frequency deviation falls by 25 percent, frequency regulation time contracts by 80 percent, and energy storage requirements decrease in ALK + PEM + batteries systems. This is relevant because the electrolyzer operation benefits from a more stable power supply.

Stability is particularly valuable for hydrogen plants that integrate continuous chemical production processes (e.g., ammonia synthesis), which require steady hydrogen flows. Large-scale projects have already adopted hybrid architectures. In China, Envision’s 500 MW Chifeng plant (Fuel Cell China 2025) and Jilin Electric Power’s Da’an project (195 MW ALK + 50 MW PEM) (AEA 2024; Lin 2024) both operate with mixed technology portfolios. In Europe, Air Liquide’s 200 MW ELYgator project at the Port of Rotterdam will deploy an ALK + PEM hybrid system (Driving Hydrogen 2025). These large-scale deployments signal growing interest in hybrid ALK + PEM architectures. Operational data collected over time will be essential, however, to determine whether the expected flexibility and performance advantages outweigh any trade-offs regarding durability, capital expenditure, and system complexity.



Solid Oxide Electrolyzer Cells (SOECs)

SOECs are the most efficient electrolysis technology when coupled with industrial-grade heat. The technology promises a 20–30 percent drop in electricity consumption in comparison with low-temperature systems. Their main advantage is integration with high-temperature processes in the ammonia and steel production sectors. SOECs rely on advanced ceramic membranes and ferritic stainless steel and spinel-coated bipolar plates. These high-cost components require complex, high-temperature manufacturing processes to achieve durability. Ongoing R&D focuses on making the stack more robust, reducing chromium poisoning, and optimizing thermal management to extend lifetimes beyond the current 20,000–30,000 hours. The designs vary in stack configuration, operating temperature, and integration strategy. When comparing vendor offers, buyers will want to scrutinize the specifications.

Overview

The technology for SOECs emerged from fuel cell research in the 1960s. Its development accelerated in the early 2000s when European and US R&D programs showed renewed interest. Advances in ceramic materials and stack design and system integration improved the efficiency of SOECs at high temperatures (700–850°C). The key differentiator of SOECs is their ability to leverage high-temperature heat—either industrial waste heat or process steam. This characteristic can lower the demand for electrical energy for electrolysis of water and gain up to 90 percent in electrical efficiency (on a lower heating value basis) under optimal conditions (IRENA 2020). The technology is therefore promising high-efficiency hydrogen production, especially for energy-intensive industries with access to abundant waste heat or high-temperature steam.

Over the past decade, SOEC technology has progressed from laboratory-scale prototypes to multi-kilowatt pilot demonstrations, with companies like Sunfire, Bloom Energy, and FuelCell

Energy driving innovation. Collaborating with research consortia, these firms have validated SOEC performance in real-world settings, laying the foundation for commercial deployment. Notable milestones include Bloom Energy's operation of SOECs in nuclear-coupled tests at the Idaho National Laboratory and the installation of a 4 MW module at NASA Ames, which can produce about 2.4 tons of hydrogen per day (Bloom Energy 2022, 2023a). In Germany, Sunfire's GrInHy3.0 project (Sunfire 2024) integrates SOEC stacks into Salzgitter's steelworks (Green Steel World 2024), utilizing process steam to support green steel production. Topsoe has demonstrated a 350 kW SOEC system and is advancing toward a 100 MW e-ammonia project in Texas, in partnership with First Ammonia (Topsoe n.d.[a]). Their robust 5,000-hour industrial demonstration, involving 12 stacks and 1,200 cells, has validated the technology under demanding operational conditions. Meanwhile, FuelCell Energy is piloting a 250 kW SOEC system at the Idaho National Laboratory to explore heat-assisted hydrogen production at a rate of roughly 150 kilograms per day.

These pilot projects reflect the momentum behind the SOEC technology and highlight robust industrial-scale initiatives in the pipeline. It is important to note, however, that SOEC systems have a limited commercial track record. Continued scaling and validation are therefore necessary to establish their viability for widespread adoption.

Technology Basis

SOEC systems operate at 700–850°C, using a ceramic electrolyte that conducts oxygen ions with steam instead of water as feedstock. This high-temperature process slashes electrical demand, making SOEC systems more attractive in energy-intensive industries abounding in waste heat or high-temperature steam. Such SOEC systems deliver baseload hydrogen at high levels of availability and efficiency. The technology exhibits less operational flexibility, however, than PEM or pressurized ALK systems while proving less durable. Typical lifetimes range from 20,000 to 30,000 hours, against 60,000 to 80,000 hours for mature ALK designs.

Flexibility and Operational Limits

SOEC systems are efficient under steady baseload conditions (abundant steam), but their high operating temperatures create thermal inertia that hinders rapid ramping. Cycling introduces mechanical stress, which in turn impairs durability. For this reason, SOEC systems are best suited for stable applications, such as industrial heat integration or hybrid systems, where minimum load flexibility is less critical than maintaining efficiency and performance under constant operating conditions. Note that SOECs can be switched to fuel cell mode when electricity prices spike, allowing the technology to produce electricity from hydrogen, ammonia, and methanol, among others. Explosion risks are intrinsically nil due to the high temperature.

Cost of Materials and Components

Unlike PEM electrolyzers, which use iridium and platinum catalysts, SOEC systems use rare earth oxides, not precious metals. Their main exposure therefore comes from the cost of yttrium, cerium, and lanthanum, as well as of the cobalt and nickel used in perovskites and electrodes (IEA 2024; Xun et al. 2025). Material costs for SOEC systems are therefore lower than those for PEM technologies.

SOEC systems use advanced ceramic and metallic materials that enable hydrogen production at high temperature. They demonstrate strong potential for efficiency. The electrolyte is typically yttria-stabilized zirconia (YSZ) or gadolinium-doped ceria (GDC), which conducts oxygen ions between two electrodes: a nickel-YSZ cermet fuel electrode and a perovskite-type oxygen electrode made of lanthanum strontium cobalt ferrite (LSCF) or lanthanum strontium manganite (LSM). Ferritic stainless steel interconnects, such as Crofer 22 APU, are coated with conductive spinels to prevent oxidation, while glass-ceramic seals maintain gas tightness (Beyrami et al. 2024; CATF 2023).

These materials allow SOEC electrolyzers to reach high electrical efficiencies, although durability challenges persist. Nickel particles in the fuel electrode can coarsen over time, reducing electrochemical activity; perovskite oxygen electrodes may undergo strontium segregation and interfacial reactions; and metal interconnects risk chromium evaporation, which poisons electrode surfaces (DOE 2024; Kaiser et al. 2025). Seal integrity also limits thermal cycling tolerance, although research on coatings and barrier layers is improving longevity (Beyrami et al. 2024). Commercial stack and modules

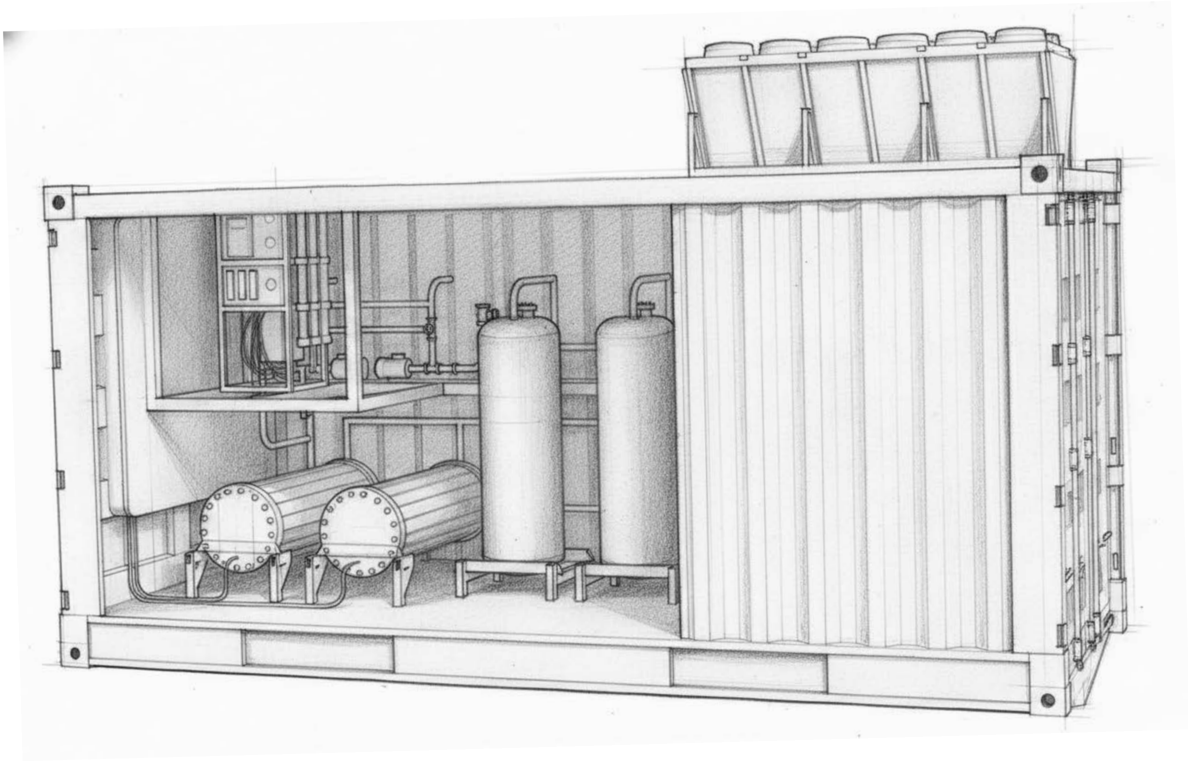
Commercial Stack and Modules

Commercial offerings for SOEC systems are still in the early stages, with vendors focusing on pilot-scale systems designed to validate performance and scalability. Bloom Energy has introduced a 4 MW SOEC module, demonstrated at NASA Ames, serving as its reference unit for near-term deployment (Bloom Energy 2023b). Topsoe, meanwhile, is advancing a flexible modular architecture built around scalable core units rather than fixed ratings (Topsoe n.d.[b]). Each 6 MW module consists of eight 12-stack cores, and the modules are designed to be replicated across industrial-scale projects ranging from tens to hundreds of megawatts.

Pathways Toward Further Improvement

Recent studies emphasize four priorities for SOEC technology to achieve commercial viability faster: durability, material optimization, realistic efficiency targets, and bankable scalability. Research is focused on developing robust oxygen-electrode chemistries, implementing barrier layers to mitigate chromium poisoning, and defining controlled operating windows to reduce damage from redox cycling and thermal stress. Improved thermal management is also vital for slowing voltage degradation over long lifetimes.

System-level modeling suggests that gentler load profiles and uniform temperature distribution can extend service intervals, even if it means sacrificing peak efficiency. This trade-off is relevant for O&M planning, where availability assumptions and life-cycle costs underpin investment decisions.



Anion Exchange Membrane (AEM) Electrolyzers

AEM electrolysis is an emerging technology, which combines the cost advantages of ALK electrolyzers with the compact design and high current density of PEM systems. Meanwhile, AEM remains constrained by challenges with membrane durability, limited lifetime, and smaller-scale deployment. Ongoing R&D into advanced polymers, catalysts, and standardized testing protocols may support the progress of this technology. The largest projects operational to date reach 5 MW, so bankability still requires demonstrated performance on the field.

Overview

Historically, AEM stack sizes were limited to laboratory-scale units of approximately 2.5 kW. However, OEMs are now advancing 25 kW class stacks. As of 2025, the largest AEM operating installations range between 4 and 5 MW, with one 20 MW facility under construction.

AEM electrolyzers operate in an alkaline environment using nonprecious metal catalysts and less expensive materials for components such as bipolar plates and electrodes. This makes AEM electrolyzers a promising solution for reducing the cost of hydrogen production while maintaining high efficiency and flexibility. AEM technology is especially suited for integration with renewable energy sources. It offers rapid response times and the possibility to adapt operations. The technology, however, is still in early development stages and will require improvement before it goes into widespread commercial adoption.

Technology Basis

The core of AEM electrolysis lies in the anion exchange membrane, which selectively transports hydroxide ions (OH^-) while blocking other ions. The membrane separates the electrolyzer's two electrodes—an anode and a cathode. At the cathode, water molecules are reduced to produce hydrogen gas and hydroxide ions. The hydroxide ions migrate through the membrane to the anode, where they are oxidized to form oxygen gas and water. Unlike PEM electrolyzers, which require expensive PGM catalysts and titanium components due to their acidic environment, AEM electrolyzers operate in an alkaline medium, allowing the use of low-cost materials such as nickel and iron for the catalysts and stainless steel for the bipolar plate (Muhyuddin et al. 2025). This feature could reduce the capital costs of AEM electrolyzers relative to PEM electrolyzers, which require scarce and expensive catalysts like iridium and platinum, a theoretical CAPEX reduction potential of 30–50 percent relative to PEM.

Membrane stability and stack longevity, however, remain limitations of AEM electrolyzers. The US Department of Energy identifies AEM as a "promising but pre-commercial" pathway, with required R&D targeting mechanical reinforcement, ionic conductivity, and chemical resilience under highly alkaline conditions. Current stack lifetimes typically range from 5,000 to 10,000 hours, which is much lower than those of ALK electrolyzers (60,000–80,000 hours) or PEM electrolyzers (40,000–60,000 hours). The design challenge is complex because the membranes of AEM electrolyzers must simultaneously satisfy three critical performance criteria: low swelling ratio, high ionic conductivity, and chemical stability. This so-called performance triangle has not yet been resolved at a commercial scale (Muhyuddin et al. 2025).

Flexibility and Operation Limits

AEM electrolyzers can operate at low minimum loads, at 3–10 percent of nominal capacity (Enapter 2025), while offering a flexibility comparable to that of PEM systems. They offer fast ramping and the ability to handle variable power inputs effectively. This makes them attractive for integration with intermittent renewables and low-load operations. However, AEM electrolyzers continue to have limited long-term durability and a scant track record, raising uncertainty around large-scale deployment and investor confidence.

AEM electrolyzers face several operational challenges. Membrane stability and ionic conductivity are critical issues especially at higher temperatures and under prolonged operation. AEM systems typically operate at temperatures between 40°C and 75°C, with some membranes showing degradation above 60°C. Additionally, the use of pure water instead of alkaline solutions can slow reaction kinetics and lower performance. Gas crossover and dynamic operations can also affect efficiency and durability, requiring careful optimization of operating conditions.

Cost of Materials and Components

AEM electrolyzers use polymer membranes that conduct hydroxide ions (OH^-) through cationic groups attached to hydrocarbon backbones supported by similar ionomers in the catalyst layer (Liu et al. 2024; Wijaya et al. 2024). These membranes enable alkaline operation without liquid electrolytes, but their chemical stability remains a challenge, as oxidizing conditions and carbon dioxide exposure can degrade or carbonate the membrane, reducing conductivity. AEM electrolyzers employ largely nonprecious metal catalysts, such as nickel-molybdenum for hydrogen production and nickel-iron or perovskite oxides for oxygen production, although small amounts of PGMs like ruthenium or iridium are at times used to improve performance (DOE 2024; Liu et al. 2024). Their metallic hardware—generally stainless steel or nickel foams instead of the titanium used in PEM stacks—further lowers costs.

While these material choices make AEM stacks less expensive than PEM equivalents and somewhat costlier than conventional ALK systems, durability is still limited by membrane and catalyst degradation (DOE 2024). Recent research shows advances in interfacial engineering and pure-water operation that improve stability (Hou et al. 2025). Overall, AEM electrolyzers offer a promising middle ground, combining low-cost, PGM-free materials like ALK with the compact design and higher efficiency of PEM technology. Long-term durability needs to improve if the AEM technology is to match the maturity of established electrolyzer types.

Commercial Stack and Modules

Commercial AEM electrolyzer stacks are designed to be modular and scalable and cater to a range of applications, from small-scale pilot projects to large industrial systems. Companies like Enapter and Power to Hydrogen have developed compact, stackable modules that can be integrated into larger systems. System suppliers emphasize modular scaling, standardized power electronics, and simplified water and gas management compatible with distributed siting.

Pathways for Further Improvement

Rapid progress across multiple fronts is addressing the durability and performance limitations of AEM electrolyzers. Research is targeting material stability, catalyst resilience, and membrane conductivity to enable long-duration operation under VRE profiles. Recent developments in electrode architecture, such as nickel iron (NiFe) foam structures and defect-engineered spinel catalysts, have demonstrated resistance to corrosion and performance degradation during high-frequency load cycling (Muhyuddin et al. 2025). These innovations aim to extend the stack lifetime and maintain high current density efficiency as the system operates under fluctuating power input typical of solar and wind energy integration.

Membrane longevity—still below 10,000 operating hours under continuous load—remains the most critical bottleneck to full-scale commercial adoption of AEM electrolyzers. Until AEM systems last for 20,000 to 40,000 hours, projects will rely on grant-based financing, public demonstration programs, and concessional credit lines rather than conventional project finance.

At the same time, the standardization of durability testing protocols is improving the comparability of results across laboratories, making more transparent benchmarking of performance and degradation rates possible. There are already some efforts in that direction, such as DNV's standard DNV-RP-J302: Performance and Testing of Electrolyzer Systems. The durability testing step is critical for bankability assessments, as it provides investors and insurers with quantifiable data on reliability to support early-stage project financing.

Box 1.4 defines several key parameters important to decision-makers and compares them across four types of electrolyzer technologies.

BOX 1.4

COMPARATIVE SNAPSHOT OF 2025 ELECTROLYZER TECHNOLOGY CHARACTERISTICS

Key investment parameters. Electrolyzer total capital expenditure (CAPEX) represents the full up-front investment required to build and commission an electrolyzer plant, including, among other elements, the stack, balance of plant, installation, civil works, and all supporting infrastructure. Electrolyzer nonelectricity operational expenditure (OPEX) refers to the ongoing operating costs of an electrolyzer facility excluding electricity and including, among others, maintenance, water treatment, labor, consumables, and stack replacements. Today's global electrolyzer markets show cost advantages for alkaline (ALK) technology across both CAPEX and OPEX, while proton exchange membrane (PEM) continues to strengthen its competitiveness as the technology matures. Solid oxide electrolyzer cell (SOEC) and anion exchange membrane (AEM) technologies remain at earlier stages of development, with a wide cost gap relative to ALK and PEM systems.

PARAMETER	ALKALINE (ALK)	PROTON EXCHANGE MEMBRANE (PEM)	SOLID OXIDE ELECTROLYZER CELL (SOEC)	ANION EXCHANGE MEMBRANE (AEM)
CAPEX installed system ($/kW)	500–1,500[a]	1,000–2,000[a]	> 3,000[a, b]	> 3,500[c]
Annual nonelectricity OPEX as a percentage of total CAPEX	2–3%[d]	3.5–5%[d]	> 3%[b]	> 5%[c]

Electrolyzer lifetime. The lifetime of an electrolyzer is a key consideration for investors: longevity affects operation and maintenance (O&M) costs and the project's revenue stability over time. Two indicators speak to longevity: stack durability, measured in total operating hours before replacement, and degradation rate, which shows how quickly stack performance declines (stacks are generally replaced once performance degrades by more than 10 percent). Lower durability or faster degradation means more frequent stack replacements, higher O&M costs, and lower hydrogen output, all of which weaken a project's financial stability. Based on the data below, among available technologies, ALK electrolyzers appear to have the longest lifetimes and lowest degradation rates. PEM systems follow, while SOEC and AEM systems still lag in proven durability. All estimates remain uncertain, however, due to the limited number of electrolyzers that have operated for decades.

BOX 1.4 *(CONTINUED)*

PARAMETER	ALKALINE (ALK)	PROTON EXCHANGE MEMBRANE (PEM)	SOLID OXIDE ELECTROLYZER CELL (SOEC)	ANION EXCHANGE MEMBRANE (AEM)
Stack durability (estimated operating hours)	60,000–90,000[e]	40,000–60,000[f]	20,000–40,000[g]	10,000–20,000[h]
Degradation rate	0.1–0.25% per 1,000 hours[i]	0.2–0.5% per 1,000 hours[j]	0.5–1.0% per 1,000 hours[k]	>1% per 1,000 hours (uncertain)[1]

Integration with VRE. The ability of an electrolyzer to operate dynamically is relevant for financiers. Dynamic operation allows the system to efficiently respond to variable renewable energy (VRE) supply, enabling the system to capture low-cost electricity and to maximize hydrogen production and support stable revenues. Two additional parameters help evaluate how different technologies integrate with VRE. The first is minimum operational load, which indicates how far the electrolyzer can reduce its output while still producing hydrogen. Lower minimum loads enable better use of fluctuating renewable output and support more predictable cash flows. The second parameter is cold-start time, or how quickly the system can restart after periods of no power. Cold starts are important for plant availability and revenue stability. The data below show that PEM and AEM technologies offer the greatest flexibility. They can operate at low loads. Meanwhile, modern atmospheric ALK systems are flexible but not more flexible than PEM and AEM technologies. PEM further stands out for its rapid cold starts, making it well suited for dynamic, VRE-driven operations.

PARAMETER	ALKALINE (ALK)	PROTON EXCHANGE MEMBRANE (PEM)	SOLID OXIDE ELECTROLYZER CELL (SOEC)	ANION EXCHANGE MEMBRANE (AEM)
Minimum load (% of nominal)	30% rated load for pressurized ALK system 10%m rated load for modern atmospheric ALK system[s]	10% rated load[n]	50% rated load[o]	5% rated load[p]
Cold-start time (minutes)	30–120[q]	5–30[r]	>360[s]	20–30[t]

Electricity demand per unit of hydrogen. Electricity is the largest cost driver in green hydrogen production, constituting 50–70 percent of the levelized cost of hydrogen. This means that the amount of electricity needed for an electrolyzer to produce each kilogram of hydrogen (expressed in kilowatt-hours per kilogram of hydrogen [kWh/kg of H2]) is a critical factor in determining operating costs, revenue stability, and overall project viability. From the data below, among today's technologies, SOEC systems achieve the highest electrical efficiency. However, they require a high-temperature heat source on site, which limits where and how they can be deployed. By contrast, ALK, PEM, and AEM electrolyzers operate in a similar efficiency range but offer no strong advantage over one another in terms of electricity consumption alone.

BOX 1.4 *(CONTINUED)*

PARAMETER	ALKALINE (ALK)	PROTON EXCHANGE MEMBRANE (PEM)	SOLID OXIDE ELECTROLYZER CELL (SOEC)	ANION EXCHANGE MEMBRANE (AEM)
Electricity consumption (kWh/kgH_2, alternating current [AC])	51–56[u]	53–56[v]	35–42[w] *(with high-T steam available on site)*	51–53[x] *(claims; limited field validation)*

Electrolyzer size. The physical volume of an electrolyzer affects land needs, installation costs, and plant layout. Size is relevant for projects anticipating insufficient available land, as with refineries or harbors. One parameter for assessing stack size for a given hydrogen output is the current density in terms of electricity current (amperes) per area of electrode (square centimeters). Higher current densities allow more hydrogen production from a smaller stack, reducing equipment volume and overall footprint. ALK systems require larger stacks for a given output. This increases requirements for land and civil works compared with PEM systems, whose compact stacks recommend it to space-constrained sites. SOEC systems feature compact cells but need large thermal BoP. AEM systems currently use larger stacks per unit of hydrogen output, with scalability expected through multimodule arrays.

PARAMETER	ALKALINE (ALK)	PROTON EXCHANGE MEMBRANE (PEM)	SOLID OXIDE ELECTROLYZER CELL (SOEC)	ANION EXCHANGE MEMBRANE (AEM)
Typical current density (amperes per square centimeter [A/cm²], stack)	0.23–0.46 (advanced: 0.6–0.9)[y]	1.0 – 2.0[y]	0.3–1.0 *(cell dependent; high T)*[y]	0.5[z] *(emerging)*

Sources:
a. World Bank staff estimates based on Rouwenhorst (2025).
b. Tanaka, Roeder, and Monnerie 2025.
c. World Bank staff estimates based on interviews with OEMs.
d. Adapted from NREL H2A and IEA benchmarking data.
e. Rolo, Costa, and Brito 2024.
f. Corigliano and Fragiacomoa 2025; Taha et al. 2024.
g. Flis and Wakim 2023; Atomfair n.d.
h. Muhyuddin et al. 2025; Jin et al. 2024.
i. DOE n.d.a; Maoulida et al. 2026.
j. Flis and Wakim 2023; Maoulida et al. 2026.
k. Flis and Wakim 2023; DOE n.d.b; Maoulida et al. 2026.
l. Clean Hydrogen Partnership n.d.
m. thyssenkrupp n.d.; Green Hydrogen Systems 2025.
n. Liu et al. 2025; Van der Roest et al. 2023.
o. SunFire n.d.
p. Klinger et al. 2024.
q. Flis and Wakim 2023; Yang et al. 2024.
r. Smolinka 2023; Flis and Wakim 2023.
s. Horizon Europe 2025; Flis and Wakim 2023.
t. Clean Hydrogen Partnership n.d.; Flis and Wakim 2023.
p. u. Bernuy-Lopez 2025; EBZ n.d.
v. Ohmium n.d.; Electric Hydrogen 2024b.
w. Bernuy-Lopez 2025; Shamsi et al. 2024.
x. Enapter n.d.
y. Cozzolino and Bella 2024.
z. Park et al. 2023.

Note: T = temperature.

Electrolyzer System Components

A consistent evaluation of electrolyzer technologies and hydrogen production projects requires defining system boundaries. Explanations for four distinct system boundaries are given below: (1) electrolyzer stack (2) BoS, (3) BoP, and (4) installation (Table 1.1). Each part encompasses a different scope of technical components and comes with cost implications.

TABLE 1.1

Schematic overview of electrolyzer system components

SYSTEM BOUNDARY	TECHNICAL SCOPE
Electrolyzer stack	Core electrochemical cells (anode, cathode, membrane/electrolyte).
Balance of stack (BoS)	Electrical and control systems: Rectifiers, transformers, cabling, switchgear, control units. Rectifiers are typically the costliest component.
Balance of plant (BoP)	Mechanical and process systems: Water purification, thermal management, hydrogen drying/purification/storage, compression, safety systems.
Installation	Engineering, procurement, construction, commissioning, as well as civil works, foundations, permitting, interconnection, and site preparation. Costs vary by geography, labor, regulation, and country risk.

Source: Ramboll (2023) and World Bank staff analysis.

Electroyzer Stack

The electrolyzer stack, where water molecules are electrochemically split into hydrogen and oxygen, is at the core of a hydrogen production system. Structurally, the stack consists of multiple electrochemical cells, each with an anode, cathode, and either a solid polymer membrane or a liquid electrolyte.

The choice of stack technology has significant implications for material costs. As a rule, ALK stacks employ nickel-based electrodes and porous diaphragms with steel hardware—a lower-cost option. By contrast, PEM stacks utilize PFSA membranes and precious metal catalysts, most notably iridium at the anode and platinum at the cathode, alongside titanium-based porous transport layers and bipolar plates. These material requirements make PEM stacks more capital intensive than their ALK counterparts. SOEC stacks use ceramic electrolytes and operate at high temperatures. They require thermally stable materials. Meanwhile, AEM stacks target cost reduction, through the use of nonprecious catalysts. Durability remains a challenge with AEM stacks.

From a performance standpoint, the stack's value proposition is determined by three interdependent parameters—efficiency, current density, and durability—which influence the levelized cost of hydrogen (LCOH), operating expenditure, and, ultimately, a project's revenue profile:

- Efficiency affects electricity consumption—the dominant cost driver in hydrogen production
- Current density influences plant footprint and CAPEX requirements
- Durability determines replacement cycles, O&M costs, and the credibility of warranties—all critical to structuring long-term debt

Balance of Stack (BoS)

The BoS encompasses the electrical and control infrastructure required to power and operate the electrolyzer stack. Key components of the BoS include rectifiers, transformers, cabling, switchgear, and automated control units. All electrolyzer types require rectifiers to convert alternating current into direct current, transformers to step down voltage, common electrical and control equipment, cabling and switchgear for safe distribution, and control systems (programmable logic controller [PLC] and Supervisory Control and Data Acquisition [SCADA]) to monitor and regulate operation.

While all these components share BoS building blocks, the rectifier and control setup vary by electrolyzer technology depending on how sensitive the stack is to power quality and how quickly it must respond to variations. From a financial perspective, BoS costs are sensitive to scale: unit costs are substantially higher in smaller-scale or distributed projects due to the absence of economies of scale, whereas large centralized systems achieve cost efficiencies through optimized integration.

Balance of Plant (BoP)

The BoP consists of all auxiliary mechanical and process systems that enable stack operation. These include water purification units, thermal management systems (cooling and heat recovery), hydrogen drying, purification and storage, compression infrastructure, and control and safety systems.

BoP configurations vary by technology. For instance, the BoP design for ALK systems depends on whether the electrolyzer operates under atmospheric or pressurized conditions. Pressurized systems require less post-electrolysis compression, whereas atmospheric designs need extensive downstream treatment and compression.

All electrolyzers have some common BoP needs: for example, clean water supply and treatment, systems to manage heat and cooling, hydrogen drying and purification, compression and storage equipment, and safety and control systems. The differences between the systems relate to the respective operating principles:

- ALK units need extra equipment to handle the caustic electrolyte, including lye storage, circulation, and gas/lye separators
- PEM systems avoid liquid electrolytes; hence, their BoP focuses on high-purity deionized water treatment and gas-liquid separation, with simpler fluid handling overall
- SOEC systems are unique in that their BoP must deliver and recover high-temperature steam and manage heat flows with insulation and preheaters. Thermal integration is key
- AEM systems are between ALK and PEM systems, with the majority requiring only clean water, like PEM systems, although some designs still circulate a dilute alkaline solution, and, so, their BoP may include small electrolyte loops

Bottlenecks remain across several BoP components. Large power transformers are among the most constrained: procurement wait times had stretched from under 50 weeks in 2020 to roughly 80–210 weeks as of 2024/25, with some utilities facing procurement windows of up to five years (Utility Dive 2025; T&D World 2025). Analyses warned of a 30 percent shortfall in US transformer availability in 2025, as similar pressures built in Europe and Asia, making transformers a major driver of cost escalation and schedule risk for hydrogen projects (Utility Dive 2025; T&D World 2025). For hydrogen developers, transformer procurement has therefore become a primary schedule risk.

High-voltage (HV) cables are under equally severe strain. Wait times for procuring standard HV cables now average two to three years and can exceed five years for HV direct current cables, with prices nearly doubling since 2019. Major manufacturers, such as Nexans and NKT, report order books committed until 2029, prompting buyers like France's transmission system operator, RTE, to secure multibillion-euro contracts years in advance (ISPT 2024). This forward contracting by grid operators illustrates how industrial users, including hydrogen developers, risk being crowded out unless they lock in supply early. Medium-voltage and switchgear equipment is similarly constrained: US utilities and EPC contractors report delays exceeding a year for breakers and e-houses. Demand from data centers and transmission upgrades is exacerbating backlogs (T&D World 2025). These shortages expose hydrogen projects, even those under 100 MW, to heightened risks of cost overruns and commissioning delays.

Defining the BoP of an electrolysis production plant is relevant for investment evaluation because it determines the scope, complexity, and cost of the infrastructure required beyond the electrolyzer stack itself, greatly influencing CAPEX.

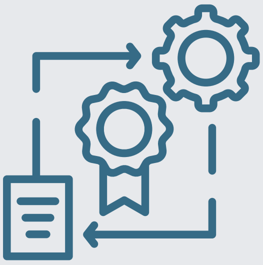
Installation

Installation encompasses the full scope of engineering, procurement, construction, and commissioning activities, including civil works, foundations, permitting, site preparation, interconnection, and integration with ancillary infrastructure. All electrolyzer projects share basic installation needs: preparing the site with civil works and foundations; setting up safe enclosures; connecting to power, water, and drainage systems; and ensuring proper ventilation, safety systems, and regulatory permits. The differences stem from the requirement of each technology. ALK systems need extra provisions for handling caustic chemicals such as potassium hydroxide, including special storage tanks, spill containment, and corrosion-resistant flooring. PEM systems are simpler to install because they require only clean water and use no harsh chemicals, although they still need high-purity water connections and hydrogen/oxygen venting. SOEC systems are more complex, as they must integrate high-temperature steam supplies, insulated piping, and special foundations that can handle heat expansion. AEM systems resemble PEM systems in layout, but if the design uses a small amount of alkaline solution, then some limited chemical storage and containment is needed.

Box 1.5 outlines relevant technical standards and certifications, both at the global and national levels.

BOX 1.5

KEY TECHNICAL STANDARDS AND CERTIFICATIONS: AN OVERVIEW



Standards are formal technical requirements, while certifications are independent verifications that the equipment complies with those requirements. In the case of hydrogen produced from water electrolysis, common international standards include the International Organization for Standardization's ISO 22734-1 (2025); ISO/TR 15916; and ISO 12100.

For renewable hydrogen project development, differences in standards and certifications across geographies directly influence bankability, permitting timelines, insurance coverage, and equipment tradability. The European Union imposes the most rigorous framework, requiring compliance with the Pressure Equipment Directive (PED), ATEX Directive, Electromagnetic Compatibility (EMC Directive), and Low Voltage Directive (LVD), and, from 2027, the EU Machinery Regulation (CEN-CENELEC 2023; EU 2023). Demonstrating conformity with these standards often adds substantial time to project schedules (e.g., from 6 to 12 months). The United States relies on the American Society of Mechanical Engineers' Boiler and Pressure Vessel Code (ASME BPVC), the National Fire Protection Association's NFPA 2/55 code, and Underwriters Laboratories' standards (NFPA 2023; ASME 2025), a fragmented system that can extend permitting by months. China offers faster and lower-cost certification through GB/GB-T standards (SAMR 2024), though these may not meet the requirements of export-oriented hydrogen offtakers or international financiers.

Misalignment across these regulatory regimes can increase capital expenditure, delay financial close, and trigger additional insurance, lender, or technical advisor requirements.

Electrolyzer System Modularity and Operational Robustness

Modularization in electrolyzer systems refers to the use of standardized, factory-built blocks (stacks integrated into containerized units or skids) that can be replicated and scaled to form commercial-scale hydrogen plants (Box 1.6). Larger modules lower installed costs by sharing major BoP components and benefiting from economies of scale, a trend highlighted in the US Department of Energy's Hydrogen and Fuel Cell Technologies Office analyses, showing much lower unit costs in plants above 100 MW (DOE HFTO 2024). The National Renewable Energy Laboratory similarly notes that clustering 10 MW PEM stacks into larger arrays materially decreases power electronics costs (NREL 2025). Concentration risk rises, however, because a single outage takes out a large portion of capacity, increasing risks of production losses. Conversely, smaller modules may raise CAPEX due to duplicated auxiliaries but improve availability, redundancy, and dispatchability.

BOX 1.6

DEFINING A CELL, STACK, MODULE, AND SYSTEM

In a hydrogen electrolysis plant, a cell is the basic electrochemical unit where water is split into hydrogen and oxygen using an electrolyte, electrodes, and a separator.

Multiple cells are assembled into a stack, with bipolar plates and flow fields enabling higher voltages and greater hydrogen output.

A module combines one or more stacks with dedicated balance of stack (BoS) auxiliaries such as manifolds, cooling, and monitoring systems, creating a standardized, factory-built block.

When an electrolyzer module is integrated into a standard 20- or 40-foot shipping container, it is referred to as a containerized module or unit. The container encloses the electrolyzer stacks along with key BoS components, creating a compact, transportable package.

When an electrolyzer module is mounted on a steel frame, it is referred to as a skid module or unit, enabling multiple components to be preassembled and factory tested prior to delivery. Unlike containerized units housed in shipping containers, skid units use an open-frame design where electrolyzer stacks are integrated with local BoS and, thanks to the additional space, can sometimes incorporate parts of the balance of plant (BoP) as well.

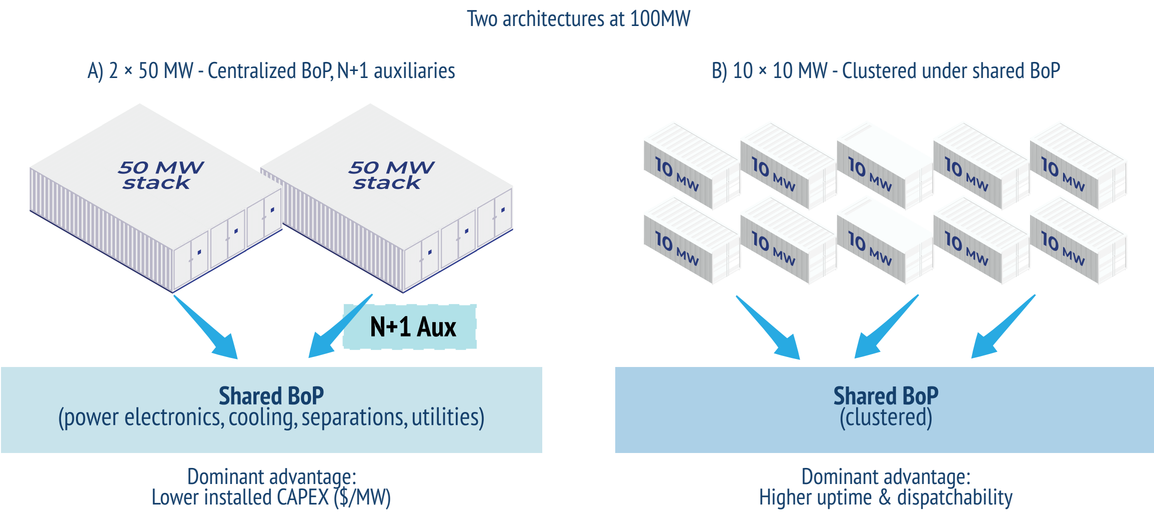
Finally, the system or plant integrates all modules with full BoP components delivering hydrogen production at commercial scale.

OEMs are therefore following this design strategy: Siemens Energy deploys 17.5 MW Elyzer P-300 arrays with modular rectifiers (Siemens Energy 2024a), Accelera's HyLYZER® 5000 provides a 25 MW building block (EGS Review 2023), and thyssenkrupp nucera's 20 MW scalum® alkaline skids interconnect unit by unit to avoid duplication (thyssenkrupp nucera 2023). Chinese OEMs also offer standardized solutions. Peric offers containerized alkaline systems with all elements integrated in a 40-foot International Organization for Standardization unit for 5–1,000 Nm³/h (information from OEM). LONGi markets skid-modular outdoor systems that combine electrolyzer, separation, purification, and power supply. LONGi launched the HyBlock in October 2025, a fully outdoor prefabricated modular design with a claimed 35 percent potential CAPEX saving for the clients (LONGi Hydrogen 2024; information provided by OEM). Sungrow promotes a "plant-as-a-product" concept with fully outdoor modular units, while Cockerill Jingli highlights modularization in its brochures, though without published external dimensions (Sungrow 2025b; Cockerill Jingli nd).

In projects where the objective is to minimize installed CAPEX, developers may prioritize fewer, larger modules supported by centralized BoP infrastructure, complemented by redundancy for critical auxiliaries (DOE HFTO 2024; Siemens Energy 2024a; Accelera by Cummins 2024). Conversely, if the dominant considerations are uptime, dispatchability, and incremental scalability, as in projects directly coupled with VRE or in regions exposed to higher outage risks, developers may adopt more modular configurations—for example, 10 × 10 MW rather than 2 x 50 MW for a 100 MW plant (Figure 1.5 and Table 1.2). This strategy enables staged expansion, enhances scheduling flexibility, and reduces exposure to single-point failures, while clustering modules under shared BoP to preserve scale economies (Nzaba Madila et al. 2025; MAN Energy Solutions 2025).

FIGURE 1.5

A comparison of modularity between architectures



Source: World Bank staff.

Note: BoP = balance of plant; CAPEX = capital expenditure; MW = megawatt; VRE = variable renewable energy.

TABLE 1.2
Modularity trade-offs in electrolyzer plant design

DIMENSION	FEWER, LARGER STACKS	MORE, SMALLER STACKS
Capital expenditure efficiency	Lower installed cost per megawatt through economies of scale and shared balance of plant (BoP); simplified engineering, procurement, and construction (EPC) integration.	Higher CAPEX due to more modules with lower production capacity.
Operational expenditure profile	Lower fixed operation and maintenance (O&M); fewer auxiliaries, but outages affect larger portions of capacity, raising downtime risk.	Higher fixed O&M from additional pumps, valves, and spares; redundancy improves availability and reduces cash flow volatility.
Uptime and reliability	Efficient for initial utility-scale build-out; limited flexibility for phased expansion.	Localized failures; redundancy can improve system availability.
Scalability and expansion	Efficient for initial utility-scale build-out; limited flexibility for phased expansion.	Supports staged expansion; modular arrays can be added incrementally to match offtake growth and financing availability.
Operational flexibility	Less suited for variable renewable energy (VRE)-coupled projects due to lower redundancy and slower redispatch.	Stronger alignment with VRE integration; modular arrays allow partial dispatch and fast response.
Maintenance strategy	Fewer components simplify routine maintenance but create higher impact during major interventions.	More auxiliary components (pumps, valves, controls) raise fixed O&M requirements, but modular design enables targeted servicing.

Sources: DOE HFTO 2024; Nzaba Madila et al. 2025.

Integration of Variable Renewable Energy and Electrolyzer systems

When electrolyzers are connected to power supply dominated by wind or solar PV generation, their operation and performance are affected by the variability and intermittency of those generation sources. Long-term variability affects the available hours of operation of the electrolyzer in a year, while short-term variability affects the dynamic operation of the electrolyzer. For project developers, the main factors shaping the integration of solar and wind energy are the capacity factor (CF), minimum load thresholds, cycling durability, shutdown tolerance, and efficiency linked to power curves.

Capacity Factor (CF)

An electrolyzer's CF is the ratio of its actual hydrogen output over a given period to the maximum possible production if it were operated at full power continuously. As electrolyzer utilization is constrained by electricity supply, the electrolyzer CF is directly influenced by the CF of the associated power generation resource. Evidence (Shin et al. 2023) indicates that the CF of renewable power sources is a primary driver of electrolyzer economics; higher CFs increase utilization and reduce the LCOH, whereas low CFs raise LCOH due to suboptimal asset use. In assessments of PV, onshore wind, and offshore wind powering ALK and PEM units, onshore wind with ALK achieved the lowest LCOH, driven by higher CF despite higher CAPEX than PV. Offshore wind (very high CAPEX) and PV (lower CF) were less competitive. These results highlight the need to balance CAPEX and CF in project design, with falling battery costs offering a pathway to raise effective CF.

Minimum Load Thresholds

An electrolyzer's minimum operational load is the lowest power input or current level at which it can operate stably while maintaining safe and efficient hydrogen production. Electrolyzers must remain above minimum load thresholds to avoid safety risks from gas crossover. At very low loads, oxygen production decreases faster than hydrogen: hydrogen migrates into the oxygen compartment and forms potentially explosive mixtures (Hyde 2025). In such cases, stacks must be shut down. This in turn necessitates cold starts and the purging of inert gas, gradual heating, and in some cases repressurization. Operating below safe loads not only increases safety risks (occurrence of explosive hydrogen/oxygen admixtures) but also accelerates degradation. Frequent cycling raises OPEX and downtime and poses a challenge to modularity and standby management.

Among technologies, ALK electrolyzers are the most sensitive to crossover. They lack a viable recombination catalyst, especially at high pressures. Pressurized ALK systems (e.g., 30 bar) face a narrower safe operating range because elevated pressure increases hydrogen solubility and diffusion, raising the risk of gas mixing. Reducing pressure to 5–10 bar improves safety and widens the load range, while maintaining modest compression benefits compared to atmospheric operation. Modern atmospheric ALK electrolyzers can operate at minimum loads, as with PEM, claiming as little as 10 percent of the rated load (thyssenkrupp n.d.). Meanwhile, to maintain gas purity and system stability, pressurized ALK designs have to operate at higher minimum loads of around 25 percent. Atmospheric ALK electrolyzers are inherently safer because of minimal differential pressure, but they require full mechanical compression downstream, which increases system cost and complexity (de Groot 2025). PEM systems effectively mitigate this risk through built-in recombination catalysts that convert crossover hydrogen and oxygen into water, reducing safety risks and allowing broader load flexibility, though with some loss of faradaic efficiency. PEM technology can operate a lower minimum load than other technologies, as low as 5 percent, as indicated by OEMs (Sungrow 2025a). Therefore, PEM has an advantage over pressurized ALK: gaining flexibility from operating electrolyzers at very low loads. Otherwise, there are few major differences between PEM and modern atmospheric ALK technologies. SOECs are largely immune to gas crossover thanks to their dense oxygen ion-conducting ceramic electrolytes (e.g., yttria-stabilized zirconia). Their risks stem largely from leaks at seals or manifolds rather than permeation (ISPT 2023). AEM electrolyzers, still in early deployment, show promising gas tightness and hydrogen purity up to 99.99 percent (Liu et al. 2024).

Degradation Due to Frequent Cycling and Shutdown

Electrolyzer degradation is the gradual loss of performance, as seen in cell voltage rising at constant current density, typically reaching end-of-life at an increase of about 10 percent. Intermittent operation and frequent cycling—common under VRE supply—accelerate degradation by inducing reverse currents, catalyst wear, and thermal-mechanical stress, adding to downtime and maintenance needs (Alia et al. 2024). ALK electrolyzers, with lifetimes of around 60,000 hours and degradation rates of 0.1–0.25 percent per 1,000 hours, are robust but degrade faster under dynamic operation because of trapped bubbles and deteriorating nickel electrodes. They perform best under steady-state conditions. PEM electrolyzers, with lifetimes of nearly 40,000 hours, tolerate rapid cycling better but exhibit higher overall degradation (0.2–0.5 percent per 1,000 hours), driven by iridium dissolution and membrane thinning at low loads (DOE 2024; EPRI 2022).

Consequently, PEM offers superior operational agility but at the cost of shorter stack life and higher long-term replacement needs. In practice, although ALK units may experience accelerated wear when operated under highly variable renewable conditions, they are more intrinsically durable than PEM stacks. A milder impact on fixed OPEX for ALK relative to PEM would be important for developers evaluating the trade-offs between flexibility, stack replacement cycles, and long-term cost of ownership in renewables-powered hydrogen projects. SOECs offer high efficiency at the cost of shorter lifetimes in the field, around 20,000 hours, and are sensitive to thermal cycling (Clean Air Task Force 2023). AEM electrolyzers remain at a low technology-readiness level, their lifetimes below 5,000 hours at this stage of development.

Frequent start-stop cycles generate reverse currents, accelerate catalyst degradation, and induce thermal stress cracking, which all create more downtime and higher maintenance costs (Alia et al. 2024). The impact of cycling varies across electrolyzer technologies: ALK systems are generally the most affected by frequent load changes, PEM and AEM stacks exhibit greater resilience, and SOEC technology is primarily impacted by thermal stress due to cycling effects.

ALK electrolyzers are more susceptible to stress during shutdown and transient operation. Rapid stops can lead to electrolyte crystallization, electrode fatigue, and seal degradation, while cyclic pressure variations increase hydrogen crossover through diaphragms. Large-scale industrial systems typically show longer start-up times and lower dynamic flexibility than PEM units, necessitating higher minimum loads and slower ramp rates to avoid mechanical and chemical damage (Alia et al. 2024). Controlled purging and repressurization are required after shutdowns, while frequent cycling accelerates wear on auxiliary equipment such as pumps and heaters, increasing OPEX and lowering reliability.

PEM electrolyzers tolerate rapid cycling and power fluctuations. Their solid polymer electrolyte enables fast load-following capabilities, making them well suited for grid-connected and renewable energy applications. But start-up and shutdown events can generate reverse currents that degrade the electrodes and the membrane-electrode assembly, particularly through platinum and iridium oxide dissolution and carbon corrosion. Robust operational controls, such as anti-reverse-current circuitry, gradual depressurization, and strict high-purity water management, are essential to extend stack lifetime and minimize O&M costs (DOE 2024).

SOEC systems are highly sensitive to thermal and redox cycling. Frequent hot-to-cold transitions or fuel-air fluctuations can rapidly degrade seals, interconnects, and electrodes. To preserve durability, operators maintain hot or warm standby conditions and avoid full shutdowns. Although recent metal-supported SOECs show improved tolerance to rapid cycling, most configurations still demand stringent thermal management and inert gas purging, resulting in O&M strategies centered on temperature control and seal integrity (Liu et al. 2024).

AEM electrolyzers remain an emerging technology with limited operational data under variable-load conditions. Early studies suggest degradation mechanisms like PEM, compounded by polymer instability under alkaline environments (Narayanaru et al. 2023). The development of reinforced membranes (such as poly[fluorene-alt-arylene] with decyl-trimethylammonium [PFT-C10-TMA]) aims to improve mechanical and chemical robustness, but large-scale field validation is still young.

Efficiency Linked to Power Curves

Electrolyzer efficiency is tied to the operating power curve. Because activation losses dominate at low loads and ohmic losses escalate at high loads, many systems reach peak efficiency at around 30 percent of rated capacity (Virah-Sawmy et al. 2024). Empirical results suggest that efficiency for a typical PEM can fall by roughly 12 percentage points between this optimum and full-load operation (Pilarczyk, Riboldi, and Nord 2022). Both PEM and ALK technologies exhibit similar efficiency-versus-load profiles, though ALK systems may show greater sensitivity to load swings than PEM (Cheng et al. 2024; Virah-Sawmy et al. 2024). Despite the efficiency drop at higher loads, hydrogen producers with access to low-cost renewable electricity generally operate electrolyzers near maximum capacity to maximize throughput. In such contexts, the business case favors annual hydrogen output and revenues over the modest savings from marginally lower specific electricity consumption at submaximal loads.

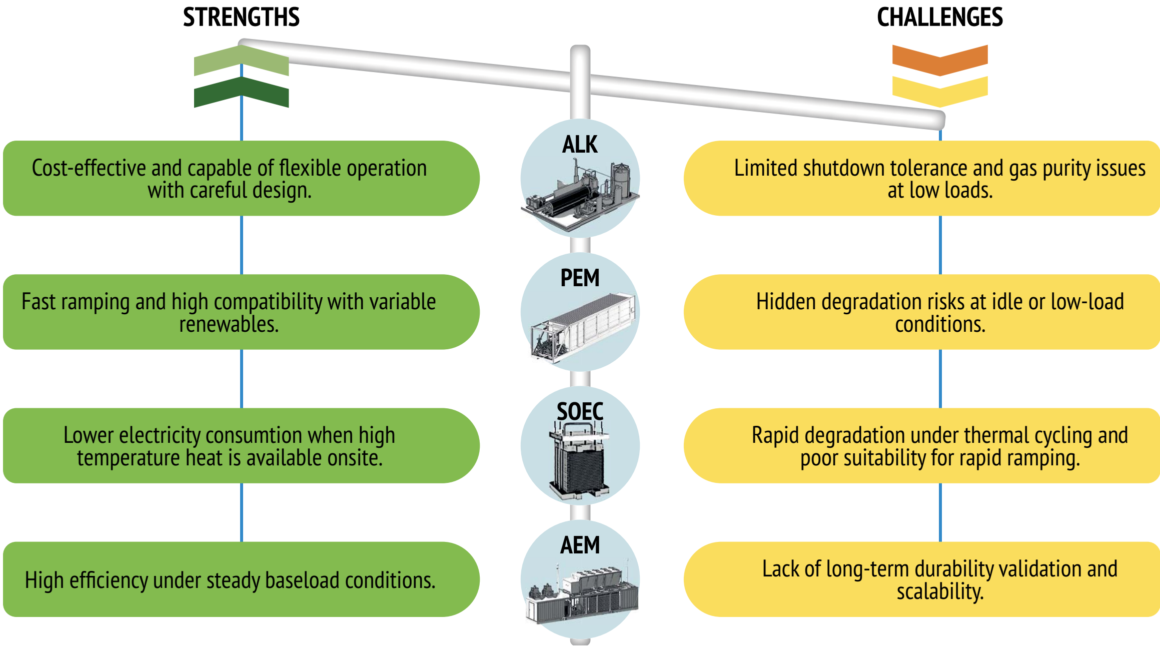
Approaches for Electrolyzer System Flexibility

In an electrolysis plant, flexibility can be engineered at three levels: (1) stack-level operations, (2) ramp rate performance, and (3) modular switch-on/switch-off strategies at the plant level (as outlined in Table 1.5):

- Operating flexibility of stacks. The ability to operate efficiently across a wide range of loads.
- Stack ramp rates. The speed at which electrolyzers can adjust to changes in power input.
- Modular switch-on/switch-off strategies at plant level. The ability to activate or deactivate modules at the system level to match available renewable energy.
- Flexibility via electricity storage on the power supply side. By buffering renewable variability, batteries can smooth ramp rates and minimum-load challenges, allowing stacks to operate more efficiently and with fewer shutdowns.

FIGURE 1.6

Technology-specific flexibility profiles



Source: DOE 2024; Eurelectric 2023, Sebbahi et al. 2024; EPRI 2022; Muhyuddin et al. 2025.
Note: AEM = anion exchange membrane; ALK = alkaline; PEM = proton exchange membrane; SOEC = solid oxide electrolyzer cell.

Operating Flexibility of the Stacks Based on Technology Choice

Flexibility profiles vary by technology. PEM electrolyzers provide fast ramping and VRE compatibility on the one hand, but on the other, face risks of degradation at idle or low-load conditions. Operators mitigate these by maintaining minimum standby loads and using batteries or grid backup, as demonstrated in Iberdrola's Puertollano project (Eurelectric 2023). ALK systems can operate flexibly with careful design but struggle with shutdown tolerance and purity at low loads (Sebbahi et al. 2024). SOEC systems excel in efficiency under steady baseload conditions but degrade rapidly under thermal cycling (EPRI 2022). AEM systems show promising flexibility at low loads but remain unproven at scale (Muhyuddin et al. 2025)

Stack Ramp Rates

The speed at which an electrolyzer can raise or lower its hydrogen production after changes in power input is known as the ramp rate, a relevant factor in the integration of electrolyzers with VRE. Each technology exhibits distinct characteristics in this regard, influencing their suitability for different operational scenarios (DOE 2024). Analyses show that ALK has an advantage over atmospheric ALK. But in locales with abundant and less variable solar and wind resources—as in more than a few EMDCs—this advantage might be marginal.

- **Alkaline (ALK) electrolyzers.** ALK systems can ramp relatively quickly but are constrained by minimum load thresholds. ALK systems can ramp relatively: 4 percent/second pressurized and 10 percent percent/minute atmospheric (John Cockerill 2024 a). Below these thresholds, operations will trigger costly shutdown purges and pose safety risks, limiting their flexibility. As a result, ALK electrolyzers are better suited for baseload or moderately variable supply profiles that leverage their cost-effectiveness and robust design.
- **Proton exchange membrane (PEM) electrolyzers.** PEM electrolyzers are characterized by near-instantaneous ramping and broad load flexibility, 10 percent/second (Sungrow 2025a), making them the most compatible with highly variable renewable inputs. Cold starts may take longer, around 10 minutes, because of the need to reach optimal operational temperatures. But frequent cycling can degrade the membrane and catalyst, necessitating hot standby strategies to maintain system integrity and performance.
- **Anion exchange membrane (AEM) electrolyzers.** AEM systems offer PEM-like ramping capabilities, promising flexibility for low-load and variable operations. Their long-term durability remains unproven, however, posing challenges for large-scale deployment and bankability.
- **Solid oxide electrolysis cells (SOECs).** SOEC units are exceptionally efficient under steady, steam-rich baseload conditions. But their thermal inertia and susceptibility to mechanical stress from cycling make them poorly suited for rapid ramping. SOECs are best deployed in applications with stable power inputs, such as industrial heat integration or hybrid configurations.

Modularity and Standby Strategies

Modular electrolyzer systems offer great load-matching potential by enabling individual stacks or modules to activate or deactivate based on available renewable energy. Operators can then scale production up or down efficiently. Energy utilization and lower operational costs are optimized. But each restart incurs penalties: time delays, compromised gas purity, and accelerated wear on system components. These factors must be managed with care to ensure system reliability and longevity.

To minimize the impact of frequent start-stop cycles, electrolyzers are often maintained on warm or hot standby during periods of low or no production (Box 1.7). This strategy consumes minimal power while preserving system integrity, reducing the time and energy required for full restarts. This strategy is particularly important for PEM systems, where frequent start/stop stresses the iridium anode (Sayed-Ahmed, Toldy, and Santasalo-Aarnio 2024; DOE 2024). Alkaline systems also benefit from constant electrolyte temperature for smoother restarts. Before resuming production, systems must undergo rigorous restart protocols to ensure safe, efficient operation. These include purging residual gases and discarding off-spec gas until purity levels meet safety standards (DOE 2024). For longer pauses, additional preservation measures are required, such as controlled ramp-down, inert gas purging, and fluid management. These protocols maintain system integrity and minimize wear, though they add complexity and cost to operations.

BOX 1.7

WARM AND COLD STANDBY, AND ELECTROLYZER EFFICIENCY

Warm standby maintains the electrolyzer near operating temperature and pressure and enables rapid ramping and smoother integration with variable renewable power. Recent studies show that warm standby consumes only 1–2 percent of nominal power for megawatt-scale alkaline (ALK), proton exchange membrane, and solid oxide electrolyzer cell (SOEC) systems, incurring only a modest 1–3 percent rise in daily electricity consumption at typical operating hours (Franco et al. 2025; Rezaei, Akimov, and Gray 2024; Zauner et al. 2019).

This small parasitic load is often justified because cold starts require more heating energy and longer ramp-up periods—especially for ALK and SOEC systems—which can increase specific electricity consumption and reduce available production time (Tanaka, Roeder, and Monnerie 2025). Moreover, warm standby reduces thermal and mechanical cycling, preserving stack durability and long-term efficiency (Barba et al. 2025; Derez, Hoogsteyn, and Delarue 2025).

By contrast, cold standby eliminates most standby electricity use—particularly for ALK and SOEC technologies—but adds to startup times. For ALK electrolyzers, cold starts may take 1–2 hours, whereas a warm start takes 1–5 minutes (Yang et al. 2023; Robinson n.d.). Consequently, warm standby generally provides greater operational flexibility, throughput, and asset longevity

Assuming an ALK electrolyzer energy efficiency of 55 kWh/kgH_2, a 1 MW system operating continuously for 24 hours would produce approximately 436 kg of hydrogen, consuming 24,000 kWh of electricity. If the electrolyzer remains in cold standby for 10 hours per day, it would operate for 13 hours plus 1 hour for cold startup, producing about 236 kg of hydrogen while consuming 14,000 kWh.

By contrast, if the electrolyzer is kept in warm standby for 10 hours per day, it would operate for 14 hours, as warm startup takes only 1–5 minutes. In this case, it would produce roughly 254 kg of hydrogen, consuming 14,150 kWh (14,000 kWh during operation plus 150 kWh during warm standby). Electricity use therefore rises by only about 1 percent, while daily hydrogen output increases by 7.6 percent relative to the cold standby case.

While results will vary depending on specific electrolyzer configurations, operating strategies, and local climate conditions, this example illustrates the operational advantage of warm standby, despite its modest increase in electricity consumption

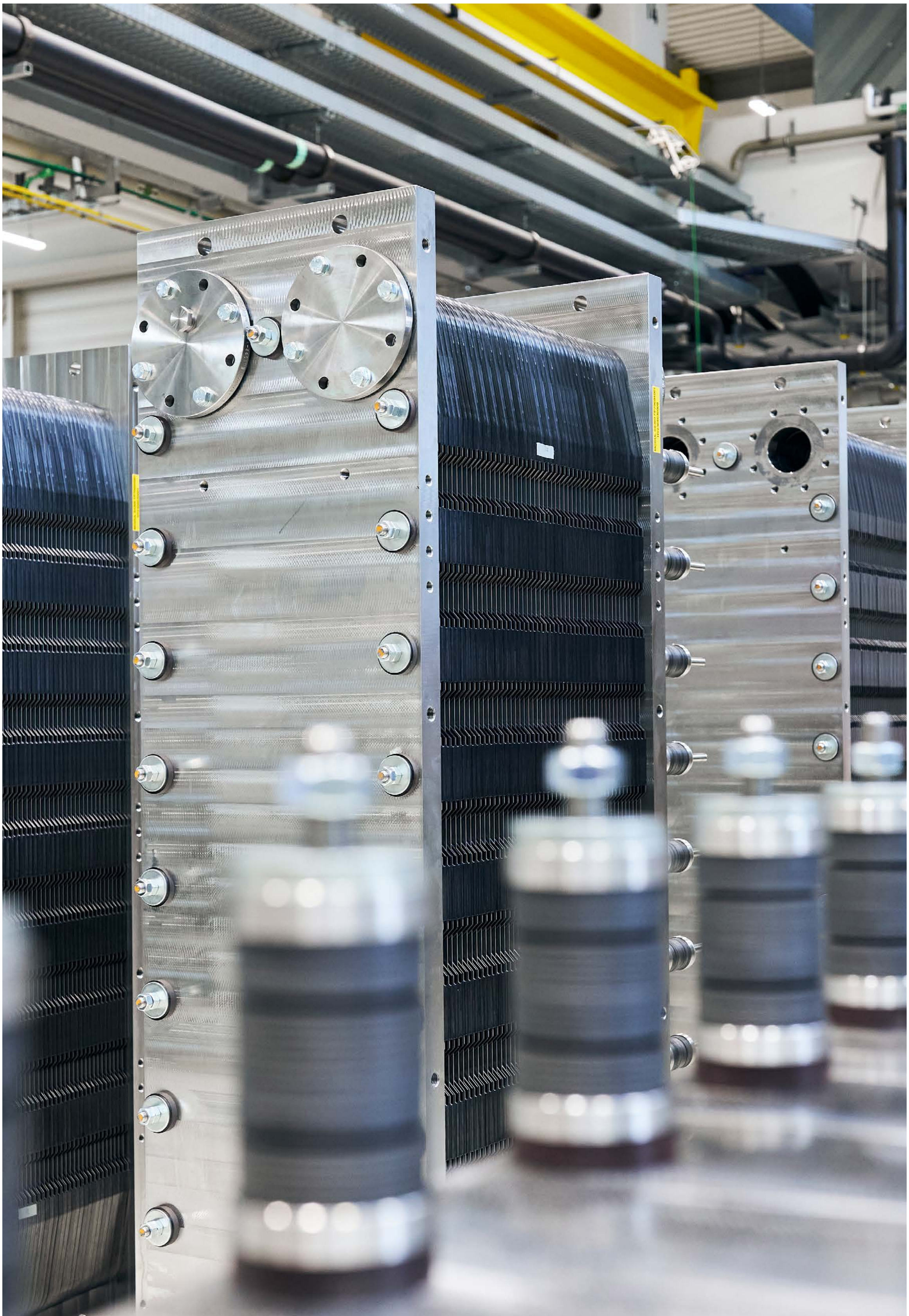
Flexibility through Electricity Storage on the Power Supply Side

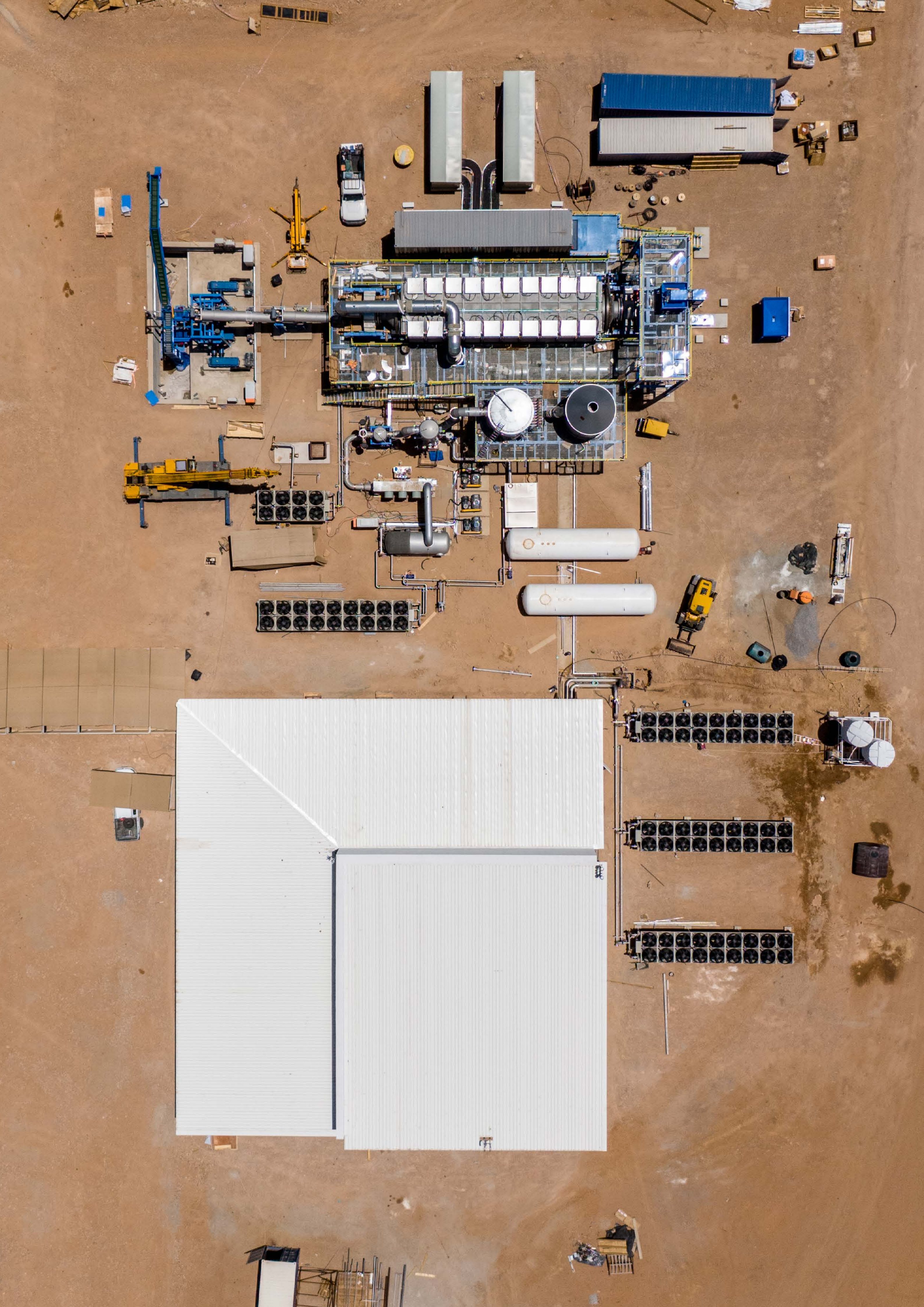
Low-cost batteries are becoming a game changer by coupling electrolysis with solar PV. Steady power supply is essential in arid regions. By buffering renewable variability, batteries smooth ramp rates and meet minimum-load challenges. Stacks operate more efficiently and with fewer shutdowns. Thus stabilized, stack life is extended and hydrogen output rises. Long-term battery storage enables the solo use of PV energy during sunny periods, as seen in Namibia, where modern electrolysis plants can achieve 11–12 hours of operational efficiency with solar power. By incorporating approximately 6 kWh of batteries for each kilowatt of electrolyzer capacity, the additional investment of around $350/kW facilitates 24-hour operation, allowing for nighttime use at half capacity.

Better-quality site resources coupled with lower battery costs are reshaping the scope of opportunities. In locations with long, stable irradiance profiles, such as many desert areas in emerging markets, the required battery capacity tends to be lower, lowering both CAPEX and cycling stress. Concurrently, sharp price declines are expanding the array of feasible configurations. Recent auction results indicate battery pack prices as low as approximately $51.6/kWh in China (Renew Economy 2024) and between $70/kWh and $80/ kWh in India (Energy World 2025).

With an assumed battery cost of around $60/kWh, extending the operating window of PV supply by five hours in a desert location (from 12–17 hours per day) would add approximately $300/kW to the electrolyzer system's CAPEX. As installed costs for ALK electrolyzers reach about $500/kW in markets like China, this would yield a total CAPEX of approximately $800/kW, making ALK systems paired with storage potentially more competitive than other electrolyzer technologies in solar-only regions without wind resources, unlocking vast areas of desert for renewable hydrogen development.

Market evidence from recent projects highlights the more rapid adoption of PV-plus-battery systems for electrolysis: For example, Iberdrola's Puertollano facility in Spain operates a 20 MW PEM electrolyzer powered by a 100 megawatt peak (MWp) solar array, complemented by a 5 MW/20 MWh lithium-ion battery system. The integrated storage solution improves plant operational flexibility and ensures a consistent hydrogen supply for ammonia and fertilizer production. Similarly, the YURI project (ARENA 2025) in Australia—developed by ENGIE, Mitsui, and Yara—features a 10 MW electrolyzer from Peric (2 x 5 MW) coupled with 18 MWp of solar generation and an 8 MW battery providing 5–8 MWh of storage. Meanwhile, Namibia's HyIron plant integrates a 12 MW ALK electrolyzer from Peric (2 x 6 MW) with 13.5 MWh of battery storage system.





II. The Cost of Electrolysis

Key Points

Understanding CAPEX Structure

- The total installed cost of an electrolyzer can be split into direct and indirect capital expenditure (CAPEX). Direct CAPEX includes the stack, balance of stack (BoS), and balance of plant (BoP). Indirect CAPEX includes engineering, procurement, and construction (EPC), installation, and various other cost components. Direct and indirect CAPEX are of similar importance.
- Though technologically critical, the stack contributes only 20–50 percent of total direct CAPEX in most modern large-scale proton exchange membrane (PEM) and alkaline (ALK) electrolyzer projects.
- Installation is the largest CAPEX component. Costs for civil works, permitting, and integration comprise 40–50 percent of total CAPEX in most modern large-scale PEM and ALK projects.
- The components of the BoS and the BoP must be clearly defined during cost estimation, as they contribute 50–80 percent of total direct CAPEX in most modern large-scale PEM and ALK projects (with significant variation depending on technology and location).
- Cost structures vary significantly depending on the location of the project. ALK systems manufactured in China are priced at $270–$280/kW for domestic Chinese markets and around $350/kW ex-factory for international markets. ALK systems manufactured in Europe or the United States are priced at $800/kW ex-factory. Installed costs for ALK systems in emerging markets and developing countries (EMDCs) are $1,200–$1,800/kW for European systems and $800/kW–$1,200/kW for Chinese systems. Prices and offers may not reflect actual cost and project size affects unit cost.
- CAPEX for PEM electrolyzers tends to differ less across regions than CAPEX for ALK systems, because they rely more on globally traded components. It is consistently higher than it is for ALK systems, however. Complete Chinese PEM systems cost $700–$1,000/

kW; counterparts manufactured in Europe and North America cost \$1,000–\$1,600/kW (ex-factory). Installed PEM units typically cost \$1,850–\$2,500/kW in China and EMDCs.

- Cost and price data change rapidly, and there are no accepted benchmarks. The winning bid at a recent Chinese auction included CAPEX of below \$100/kW for stack and BoS, but excluding BoP. This is 60 percent below 2022 levels (the extent to which this bid covers actual costs is unclear).
- Solid oxide electrolyzer cell (SOEC) and anion exchange membrane (AEM) electrolyzers are the most capital-intensive options. The installed CAPEX of pilot-stage SOEC systems is \$5,000–\$5,800/kW—far above that of ALK or PEM systems. At industrial scale, both SOEC and AEM system equipment can be delivered for less than \$2,000/kW, according to manufacturers. As manufacturing capacity expands, material use is optimized and component standardization improves.

Understanding the LCOH Components

- The levelized cost of hydrogen (LCOH) is affected primarily by operational expenditure (OPEX), with CAPEX playing a secondary role. The best projects today can produce hydrogen at around \$3/kg, but most projects face higher manufacturing costs.
- Electricity is the most significant OPEX, making it a key driver of project economics. It is highly location dependent.
- The operational flexibility of electrolyzers can enable efficient utilization of low-cost power, reinforcing the importance of aligning system design with local energy profiles for least-cost solutions. ALK electrolyzers are generally the most cost-effective option for hydropower sites or projects with stable access to low-cost renewable electricity. They are increasingly being considered for emerging solar-plus-battery configurations. PEM systems offer superior ramping capabilities and operational flexibility, making them better suited for wind or hybrid solar-wind applications with a lot of intermittency. As technology matures, AEM may emerge as a lower-cost alternative to PEM in similar use cases. SOEC systems, with their high efficiency at high temperatures, are best suited for locations with minimal power variability and access to high-temperature waste heat.

Cost Reduction Opportunities

- Standardization and modularization reduce both CAPEX and OPEX, by reducing labor, construction, and maintenance costs as well as downtime. Containerized BoP units enable these efficiencies but are typically limited to 2.5–5.0 MW scales. Larger systems may require skid-mounted solutions or on-site assembly.
- The engagement of EPC contractors and the scope of civil and structural works affect project costs. Experienced developers with standardized designs and established

contractor networks can often bypass EPC arrangements. In first-of-a-kind projects, complexity and risk typically necessitate full EPC involvement.

- Economies of scale are evident across all major components and subsystems of hydrogen production projects. Smaller-scale projects typically face significantly higher unit costs, underscoring the cost advantages of scaling up. The market electrolyzer unit cost must be considered in the light of project sizes.
- A key contributor to the gap between projected and actual electrolysis project costs is the frequent underestimation or omission of critical CAPEX components. Structural factors also play a significant role, particularly in EMDCs, where macroeconomic challenges such as high inflation, elevated borrowing costs, and persistent supply chain disruptions often contribute to cost overruns.
- The weighted average nominal cost of capital before tax credits effects ranges from 8.9–18.9 percent, indicating the critical importance of financing for LCOH.
- Significant cost reduction is expected in the coming years, and cost data will require regular updating.

This chapter presents a comprehensive analysis of cost drivers in renewable hydrogen projects, with a focus on electrolysis systems. As the core technology for green hydrogen production, electrolyzers significantly affect the LCOH through both CAPEX and OPEX. By examining actual versus projected costs, technology-specific characteristics, and both direct and indirect expenses, the chapter clarifies the financial and technical parameters essential to project bankability.

The chapter progresses through a sequence of analytical phases. It begins with an overview of the cost of electrolysis, followed by a detailed examination of capital expenditure. This includes a distinction between direct and indirect CAPEX, with direct costs analyzed across the electrolyzer stack, the balance of system, and the balance of plant, focusing on cost drivers, component shares, and expected cost-reduction pathways. Indirect costs are assessed through EPC-related and other ancillary expenditures, alongside an analysis of cost variability and its implications for overall project economics.

The discussion then turns to operating expenditure, distinguishing between fixed and variable costs and highlighting the role of efficiency, degradation, and resource consumption. Building on this, the chapter examines the levelized cost of hydrogen, presenting the calculation methodology and assessing its sensitivity to key technical and financial parameters.

The analysis subsequently considers regional differences in electrolysis equipment costs, comparing alkaline and PEM systems and addressing non-cost factors such as supply-chain localization, policy incentives, and system integration. The chapter concludes by synthesizing the main cost components and offering strategic insights for developers and policymakers seeking to deploy cost-effective renewable hydrogen projects.

Overview of Expenditures

Electrolysis systems involve multifaceted cost structures, including CAPEX for equipment and installation, OPEX for maintenance and energy input, and financial metrics such as the LCOH. A nuanced understanding of how technical parameters (such as electrolyzer efficiency and degradation) interact with economic factors (such as energy prices, capital structure frameworks, and economies of scale) is essential for stakeholders aiming to deploy cost-effective hydrogen solutions. These dynamics are instrumental in shaping adoption trajectories across industries.

Several key economic assumptions underpin the scaling of the renewable hydrogen industry:

- The investment costs of electrolyzer units will decline, driven by technological innovation and manufacturing scale-up.
- Dependable, abundant, low-cost renewable electricity, which is vital for competitive hydrogen production, is available.
- Affordable financing to support capital-intensive infrastructure mechanisms is available.
- The cost of conventional hydrogen production—particularly from fossil-fuel-based sources—will rise, as a result of increasing carbon pricing and tightening regulatory frameworks.

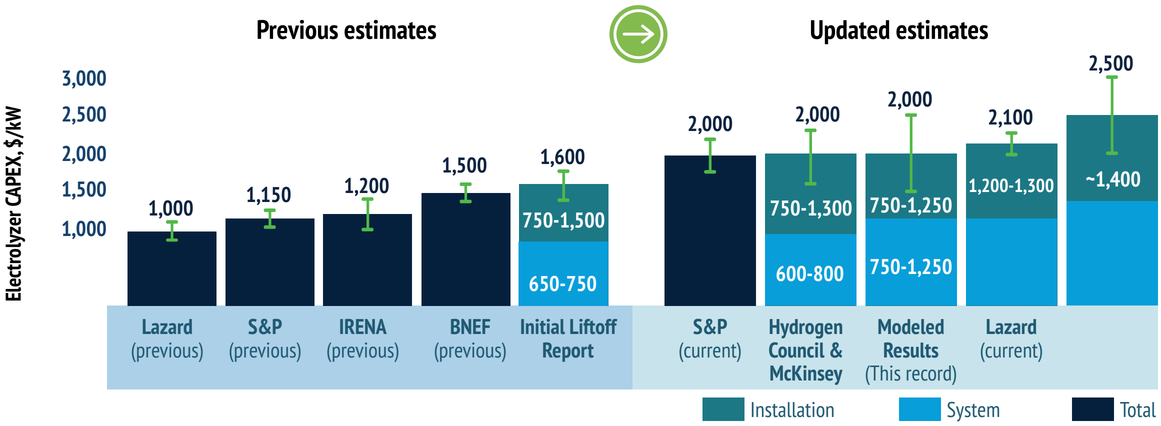
Data are casting some doubt on the first assumption (declining electrolyzer costs). Leading energy agencies have forecast aggressive cost reductions based on innovation, economies of scale, and policy support, but recent empirical evidence from commissioned and procured projects suggests that costs have risen in many parts of the world. For example, the US Department of Energy reports that the capital cost for installed electrolyzers—across both PEM and ALK technologies—increased from \$1,400–\$1,600/kW in 2023 to around \$2,100/kW in 2024 (Figure 2.1). This significant deviation from earlier projections underscores the need for a more grounded understanding of cost drivers, especially as stakeholders plan for large-scale deployment.

Rising installation expenses—linked to inflation and unforeseen implementation challenges rather than higher equipment prices—are the main cause of the increase in project costs across the industry. Equipment-level costs for electrolyzer stacks, BoS, and BoP are beginning to decline, thanks to technological advances and competitive procurement, but these reductions have not yet translated into lower installed costs, which continue to meet or exceed the upper bounds of earlier projections.

Sinopec's Ordos green hydrogen project illustrates the rapid decline in equipment prices (Box 2.1). Without the disclosure of installed cost data, however, it remains unclear whether these equipment-level savings will offset broader installation-related cost pressures.

FIGURE 2.1

Two sets of estimated electrolysis system costs in European and North American markets



Source: DOE 2024.

Note: The original estimates were made in 2023. The updated estimates were made in 2024. BNEF = Bloomberg New Energy Finance; CAPEX = capital expenditure; IRENA = International Renewable Energy Agency; kW = kilowatt.

The divergence between projected and actual installed costs of projects reflects deeper structural issues. In EMDCs, macroeconomic factors such as inflation, high interest rates, and persistent supply chain disruptions have contributed significantly to cost overruns. In addition, a gap exists between the design assumptions used in early public cost estimates and the technical and operational realities of real-world hydrogen systems. These discrepancies, which are evident across the world, suggest that initial projections often underestimated the complexity, customization, and site-specific requirements necessary for fully functional installations (Ramboll 2023).

A key contributor to this discrepancy is the incomplete accounting of CAPEX in many analyses. Earlier studies frequently omitted critical subcomponents of direct CAPEX and/or excluded indirect CAPEX entirely. To provide a more complete picture, the following analysis incorporates both direct and indirect elements of CAPEX (Figure 2.2). Based on industry surveys, case studies, and recent electrolyzer cost reports, large-scale greenfield hydrogen projects (typically in the hundreds of megawatts) exhibit a direct-to-indirect CAPEX ratio ranging from 70:30 to 65:35 (Figure 2.3). The EPC contractor plays a pivotal role in shaping indirect CAPEX, particularly through design customization, site integration, and project execution strategies.

Given the diversity in project scale, design, and execution models, there is no universal CAPEX benchmark for electrolysis systems. Cost estimates must be contextualized based on technology type, project configuration, and delivery strategy.

BOX 2.1
THE SINOPEC ORDOS ELECTROLYZER TENDER, SEPTEMBER 2025

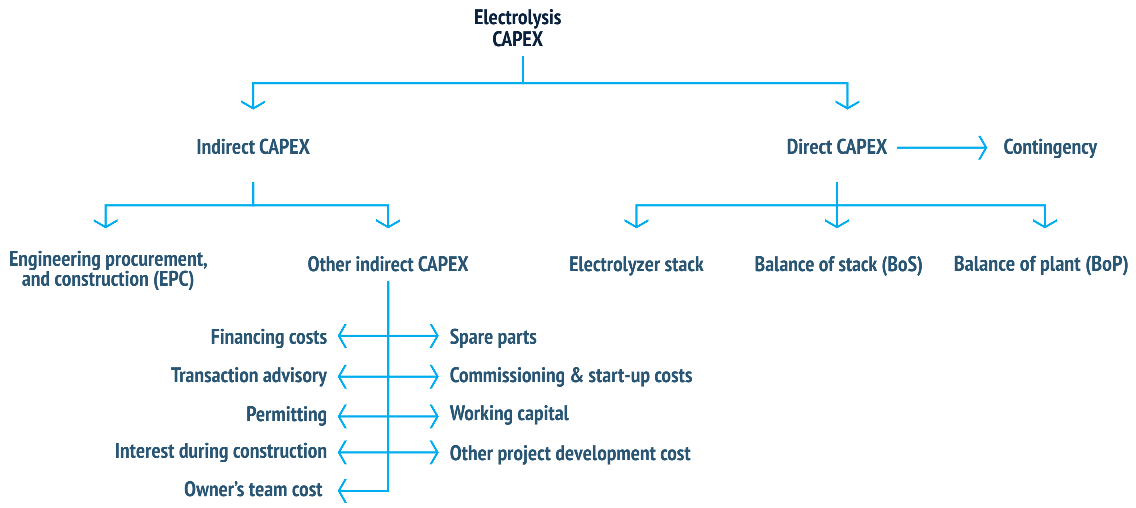
Sinopec's Ordos green hydrogen project in Inner Mongolia marks an inflection point for China's electrolyzer industry, two years after the flagship Kuqa development. The tender, comprising 48 alkaline stacks rated at 1,000–1,500 normal cubic meters per hour (Nm³/h)—around 5–7 MW per unit—was the largest publicly disclosed procurement in China in 2025. The awarded prices averaged around $75/kW, including taxes but excluding the balance of plant (BoP). The 60 percent cost reduction since 2022 reflects rapid manufacturing scale-up, material standardization, and intensified domestic competition. The awards—to LONGi, SANY, and Huadian Engineering—indicate a market in which volume and positioning have overtaken profitability as primary drivers (China Green Insight 2025).

This decoupled configuration—excluding BoP systems such as air separation, purification, and cooling units—redefines value chain interactions. Developers now retain engineering autonomy to optimize BoP design and integration, and original equipment manufacturers lose the bundling leverage inherent to turnkey packages. BoP providers are compelled to engage directly with project developers, signaling a transition toward a more modular and flexible system architecture. Such unbundling may accelerate technology differentiation on integration and performance optimization rather than hardware fabrication alone.

Sinopec introduced stringent qualification criteria to reinforce this competitive repositioning. Bidders were required to demonstrate delivery of at least eight 1,000 Nm³/h alkaline units after 2022, possess a minimum 5 MW full-stack testing platform, maintain a debt-to-equity ratio of less than 80 percent, and substantiate ownership continuity in cases of restructured entities. These requirements eliminated 7 of the 15 participants, including prior Kuqa partners CSSC Peric and Tianjin Mainland. The outcome reveals a maturing, performance-oriented electrolyzer market in which cost compression, technological credibility, and financial resilience determine survivability.

FIGURE 2.2

Breakdown of indirect and direct capital expenditure for an electrolysis system

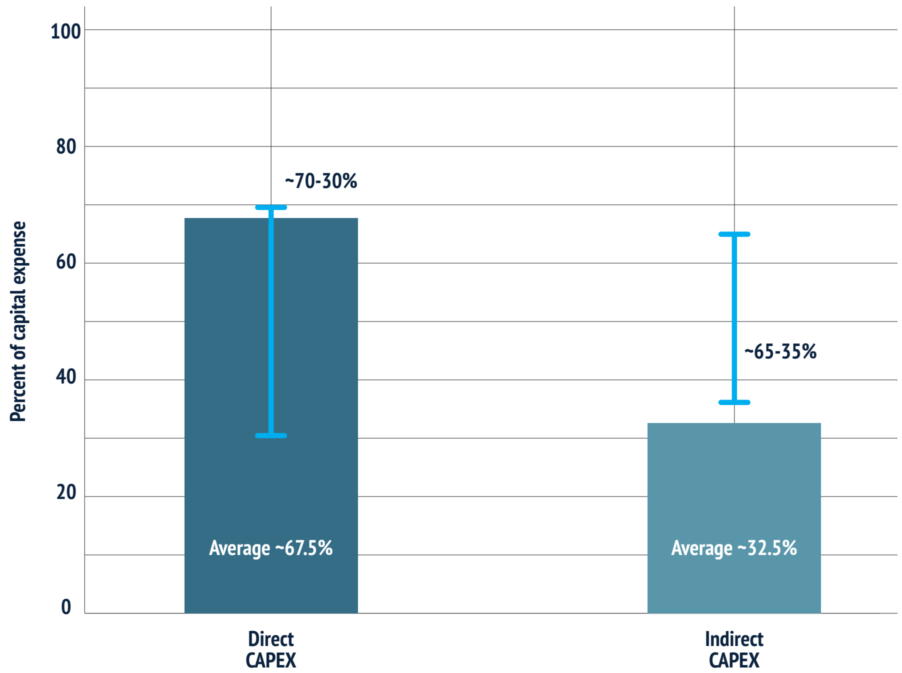


Source: World Bank staff.

Note: CAPEX = capital expenditure.

FIGURE 2.3

Capital costs of large greenfield hydrogen project, by share of direct and indirect costs



Sources: World Bank staff, based on data from BNEF (2024); DOE (2024); IEA (2025); Ramboll (2023); and Wood Mackenzie (2024).

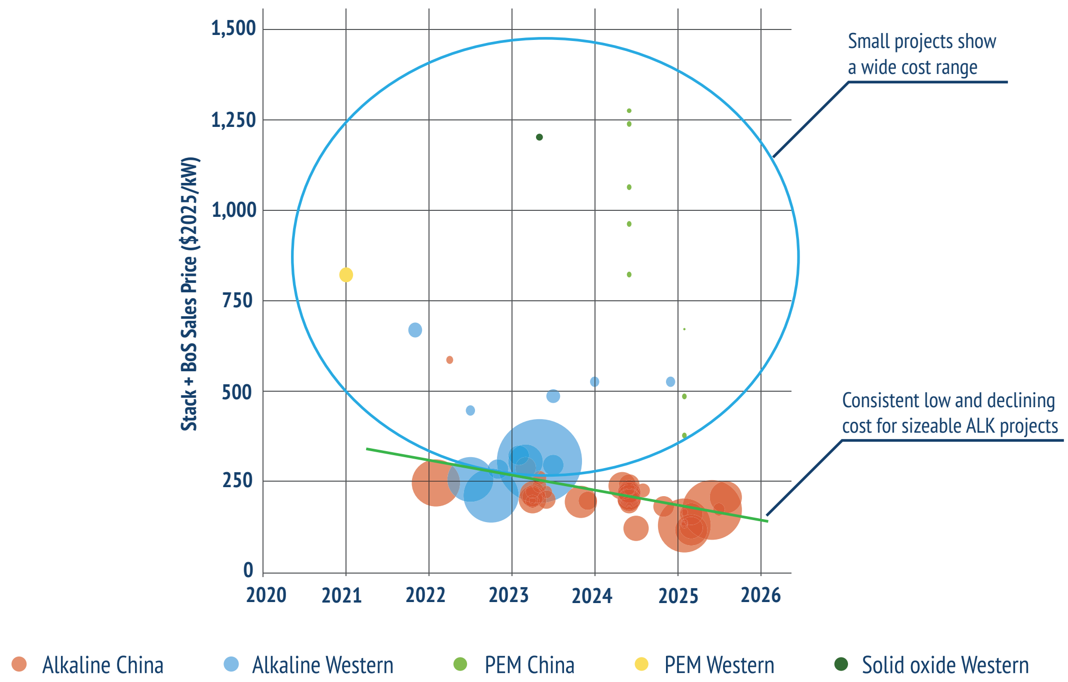
Note: Indirect CAPEX is higher for first-of-a-kind, remote, and high-risk sites. CAPEX = capital expenditure.

Several factors affect electrolyzer system costs. They include project scale, electrolyzer technology and manufacturer, and the year of commissioning. BoP costs are highly site specific and are affected by end-use requirements. Stack and BoS costs are more amenable to cross-geographic comparison, as long as contextual variables are normalized.

Figure 2.4 presents sales price data for stacks and associated equipment between 2021 and 2025. They reveal a cost range of $125 to over $1,250/kW. The lower end of the range applies to large systems. ALK electrolyzers consistently rank as the most cost-effective, with Chinese units generally priced lower than North American and European ones (labeled "Western" in the Figure).

FIGURE 2.4

Cost of electrolyzer equipment, by technology and source, 2021–25



Source: Based on Kevin Rouwenhorst analysis using various sources (Rouwenhorst 2025).

Note: Size of bubbles represents project size. BoS = balance of stack. kW = kilowatt; PEM = proton exchange membrane.

Figure 2.4 indicates a clear correlation between project size and cost efficiency. Larger installations tend to benefit from economies of scale, resulting in lower unit costs, and smaller projects exhibit greater cost variability. A modest downward trend in equipment pricing is also observable over time, though it remains uneven. These insights suggest that strategic procurement and scaling can improve cost economics, particularly in the acquisition of core equipment.

However, equipment costs represent only a fraction of the total installed cost of an electrolyzer system. Indirect CAPEX—including financing, installation, integration, and site-specific adaptations—contributes significantly to project costs and must be considered in any comprehensive cost assessment.

Direct Capital Expenditures

The capital costs of electrolysis systems are frequently presented as a single aggregated metric, typically dollars per kilowatt. Although this format is useful for high-level benchmarking, it oversimplifies the complex cost architecture of a renewable hydrogen production facility and can obscure critical insights needed for effective project planning.

A detailed understanding of the system's constituent components is essential to accurately manage, optimize, and de-risk CAPEX. Electrolysis facilities are not monolithic units but integrated process plants composed of multiple subsystems. Their cost structure can be segmented into three layers: the electrolyzer stack, the BoS, and the BoP. Each layer has its own cost drivers, levels of technological maturity, and potential for cost reductions. This layered approach facilitates cost estimation and supports informed decision-making across the design, procurement, and financing stages.

Cost of the Electrolyzer Stack

The electrolyzer stack is the core component of the facility, where the essential process of splitting water into hydrogen and oxygen takes place. It is composed of repeating electrochemical cells—often numbering over 100 in large-scale systems—each playing a crucial role in facilitating fundamental reactions. Factors that affect the cost of the stack include the sophistication of materials involved, the intricacies of the manufacturing process, and the degree of reliance on critical raw materials.

Key Components and Cost drivers

Key components and cost drivers include the following:

Membranes and electrodes. Membranes and electrodes form the functional core of each electrolysis cell, enabling the electrochemical splitting of water into hydrogen and oxygen. The membrane serves as an ionic conductor, allowing the selective passage of protons or hydroxide ions while preventing gas crossover between the hydrogen and oxygen compartments. Electrodes (anode and cathode) facilitate the redox reactions by conducting electricity and catalyzing the water splitting process.

Bipolar plates. Bipolar plates separate individual cells and distribute water and gases evenly across the cells while conducting electricity between them. They also provide mechanical support and help manage heat and fluid flow within the system.

Catalysts. Catalysts accelerate the chemical reactions that split water into hydrogen and oxygen, thereby lowering the energy required for the process, improving efficiency, and reducing power consumption.

Assembly and manufacturing. Stack assembly involves labor-intensive processes, precision engineering, and stringent quality control to stack and seal hundreds of individual cells. Initially, electrolyzer stacks were assembled manually, with technicians hand-fitting membranes, electrodes, and seals. While effective for prototyping and small-scale production, this approach limited throughput, consistency, and scalability. Over time, manufacturers introduced semiautomated assembly lines incorporating precision tooling and standardized quality assurance protocols, which improved reliability and production rates. Today, leading electrolyzer manufacturers are transitioning toward fully automated roll-to-roll and robotic assembly systems. These advanced manufacturing techniques enable high-volume production with reduced labor costs, improved component uniformity, and faster deployment timelines, which are critical for meeting the growing demand for renewable hydrogen at scale. Membranes and electrodes, bipolar plates, and catalysts differ across the four types of electrolyzer technologies (Table 2.1).

Share of the Stack in the Direct CAPEX and Future Cost Reduction Strategies

CAPEX allocation across hydrogen production plant components varies widely, because of differences in project scope, system boundary definitions, and technology configurations. A comparative review of recent sources (BNEF 2024; DOE 2024; IEA 2025; Ramboll 2023; Wood Mackenzie 2024) indicates that the electrolyzer stack typically comprises 20–50 percent of direct CAPEX, with an average of around 35 percent. This variability reflects differences in technology type, integration complexity, and procurement strategies. The higher end of this range is associated with PEM and SOEC systems, which require more advanced materials and engineering. ALK systems typically occupy the lower end of the stack-related CAPEX range. As they mature and achieve commercial viability, AEM technologies are expected to approach ALK systems' cost structures in the future.

Cost reduction in electrolyzer stacks can be achieved through advances in manufacturing, material substitution, and performance optimization, as discussed below:

Manufacturing efficiency. Scaling up and automating production—particularly via roll-to-roll coating of catalyst-coated membranes on gigawatt-scale lines—can substantially reduce labor and overhead costs.

Material substitution. Alloying strategies and the development of nano-structured catalysts are reducing the need to use precious metals, especially iridium in PEM anodes. Replacing costly titanium bipolar plates with coated stainless-steel alternatives (using niobium- or carbon-based coatings) offers further cost savings.

TABLE 2.1

Key components and cost drivers of the electrolyzer stack, by type of technology

	TECHNOLOGY			
Component	**Proton exchange membrane (PEM)**	**Alkaline (ALK)**	**Solid oxide electrolyzer cell (SOEC)**	**Anion exchange membrane (AEM)**
Membranes and electrodes	Use thin perfluorosulfonic acid polymer membranes and electrodes coated with catalysts made of precious metal (e.g., platinum, iridium). These components offer high efficiency but raise system costs because of the expensive materials used and stringent purity requirements.	Use porous diaphragms and nickel-based electrodes. Cost drivers include the materials and fabrication of large-area cells, a relatively mature manufacturing process.	Use ceramic membranes made of stabilized zirconia, paired with nickel-zirconia fuel electrodes and perovskite-based oxygen electrodes. These advanced ceramics are central to the stack architecture. They are one of the highest-cost components, because of their complex manufacturing.	Use alkaline-stable polymer membranes supported by nickel-based porous structures. By avoiding costly fluoropolymers and precious metals, they offer a lower-cost alternative to PEM. They are under active development for commercial viability.
Bipolar plates	Made of titanium with a protective coating to prevent corrosion. Advanced stacks are now using coated stainless steel to reduce costs.	Typically use nickel-plated steel as a cost-effective alternative to titanium.	Made from ferritic stainless steel coated with protective spinels to resist corrosion and improve conductivity. Because of their size and numbers in the stack, they are among the largest cost drivers.	Stacks rely on stainless steel or nickel-coated steel plates, which reduces hardware costs and makes manufacturing simpler.
Catalysts	Relies on platinum (cathode) and iridium (anode). Iridium is extremely scarce, and its price is volatile. The membrane and catalyst loading are among the primary cost drivers. The catalyst and membrane can constitute more than half of the stack's cost.	Uses nonprecious metal catalysts that are typically nickel based, offering a significant cost advantage.	Catalytic activity comes mainly from nickel in the fuel electrode and perovskite oxides in the oxygen electrode, avoiding heavy reliance on precious metals. Their cost impact is smaller than that of ceramics and plates.	Nickel-iron and nickel-molybdenum alloys replace scarce platinum or iridium, cutting catalyst and overall stack costs substantially.

Source: World Bank staff analysis.

Performance optimization. Operating stacks at higher and more stable current densities, enabled by durable membranes and optimized transport layers, reduces the required active area per kilowatt. Doing so leads to lower consumption of membranes, catalysts, and plate materials.

Durability enhancements. Improvements in stack longevity, reduced degradation rates, and extended replacement intervals allow capital costs to be amortized over larger hydrogen output, improving overall system economics.

Cost of the Balance of Stack (BoS)

The BoS comprises the essential components directly interfacing with the electrolyzer stack, typically mounted on the same skid or within the same module. These systems condition inputs and process outputs to maintain the stack's optimal operating window. The BoS is critical for performance, efficiency, and safety.

Key Components and Cost Drivers

Key components of the BoS include the following:

Power conversion unit (PCU). The PCU is typically the most expensive component within the BoS for electrolysis plants. It consists of a transformer and a rectifier. The transformer adjusts the incoming alternating current (AC) voltage from the grid to a level suitable for electrolysis operations. The rectifier converts this AC power into the stable, low-voltage, high-current direct current (DC) required by the electrolyzer stack. In large-scale installations, these units are custom engineered for high efficiency and reliability. The cost of the PCU depends on the prices of raw materials, such as copper and steel, and semiconductor components, such as the insulated gate bipolar transistors used in rectifiers. The PCU can account for 5–15 percent of direct CAPEX, rivaling the cost of the electrolyzer stack itself (BloombergNEF 2024). Long lead times, particularly for large transformers, which may require 12–18 months for delivery, pose significant risks to project schedules and must be factored into planning and procurement strategies, with some original equipment manufacturers (OEMs) partnering with power electronics manufacturers.

Control system and instrumentation (C&I). C&I equipment includes programmable logic controllers, sensors, analyzers, and monitoring devices that ensure that the unit operates safely and efficiently. Their role is to regulate stack current and voltage, manage start-up and shutdown, monitor gas and water quality, trigger safety interlocks, and provide real-time supervision through the human-machine interface (HMI) and the supervisory control and data acquisition (SCADA) interface. This equipment is a very important component of the BoS. It costs less than the PCU.

Electrolyte tank and gas-electrolyte separator. In ALK systems, the electrolyte tank and gas-electrolyte separator are critical components that support system functionality by storing and circulating the alkaline solution (typically potassium hydroxide) and separating entrained hydrogen and oxygen gases from the liquid stream to ensure product purity and operational safety. Although technically straightforward, the fabrication of these units is labor intensive, contributing to large cost differences between European and Chinese electrolyzer systems. Because these components are relatively simple to manufacture, they can easily be built in the country of deployment rather than imported, provided they meet required specifications. European and North American electrolyzer manufacturers are increasingly looking to source these components locally, reducing CAPEX and improving project economics without compromising performance.

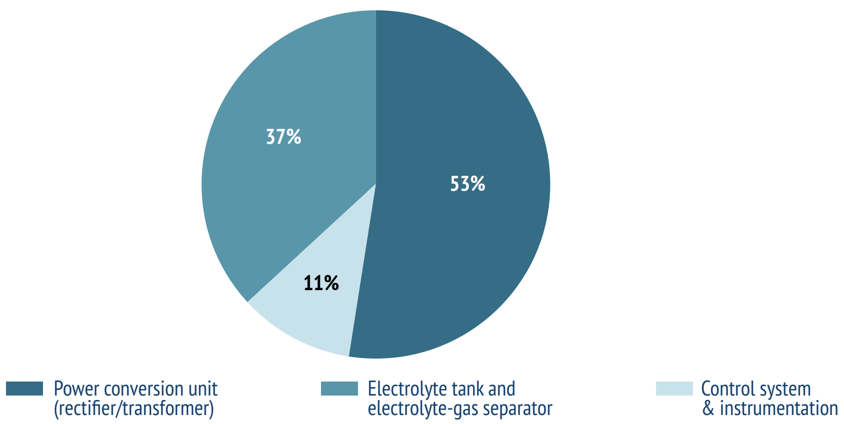
Share of Balance of Stack in Direct Capital Expenditures and Projected Cost Reduction Trajectories

In mature-scale electrolysis projects, the BoS typically accounts for 10–30 percent of direct CAPEX, with an average around 20 percent (BNEF 2024; DOE 2024; IEA 2025; Ramboll 2023; Wood Mackenzie 2024). All percentage figures that follow are based on these sources. Relative to the process of reducing electrolyzer stack costs, reducing BoS costs relies less on technological breakthroughs and more on supply chain optimization, design standardization, and economies of scale in manufacturing.

Cost allocation across individual components of hydrogen systems can vary considerably, depending on project-specific configurations, technology choices, and regional factors. Representative values derived from published studies and industry benchmarks nevertheless offer a useful basis for understanding component-level contributions. The figures shown in Figure 2.5 are not intended to reflect actual project costs but to demonstrate the relative distribution of BoS subsystem expenditures. They are intended to support comparative assessments and inform early-stage cost-optimization strategies. For illustrative purposes, total direct CAPEX is assumed to be $1,000/kW, with BoS costs estimated at $190/kW. The PCU accounts for the largest share of BoS costs, underscoring its critical role in system integration and overall performance.

FIGURE 2.5

Representative breakdown of balance of stack costs



Source: World Bank staff analysis, based on discussions with OEMs and project developers.

BoS components represent a critical area for cost optimization in electrolyzer systems. Future reductions are expected to stem from improvements in efficiency, simplification of system architecture, and widespread adoption of modularization. Descriptions of major components follow.

High-efficiency silicon carbide (SiC) rectifiers are already reducing conduction and switching losses, thereby lowering energy consumption and cooling requirements. Over the next decade, SiC-based designs are projected to become the industry standard, enabling smaller footprints and reduced material intensity.

Modular PCU architectures and factory-integrated PCU modules are expected to accelerate cost declines by streamlining assembly, improving scalability, and reducing on-site labor costs.

Emerging DC coupling strategies, which eliminate intermediate AC conversion stages, represent a transformative opportunity to cut both capital and operational costs while improving system efficiency. As renewable generation increasingly shifts toward DC-based architectures, direct coupling with electrolyzer stacks could become a design paradigm.

Digitalization and automation will reduce the cost of C&I. Advances in smart energy management systems, real-time sensing, and predictive control algorithms can optimize stack utilization and enable condition-based maintenance, reducing unplanned downtime and extending equipment lifespan. Integration of artificial intelligence (AI)-driven diagnostics and cloud-based monitoring platforms is expected to lower OPEX by minimizing manual interventions and improving asset reliability. Although C&I currently contributes just 1–3 percent of direct CAPEX, it is strategically important, because it enhances system availability and reduces life-cycle costs—key factors in lowering the LCOH.

Cost of the Balance of Plant

The BoP encompasses all sitewide infrastructure required to support the integrated stack and BoS. It includes all civil, mechanical, and electrical works that tie the facility to its utilities and offtake networks. BoP costs are highly site specific and subject to local construction and labor markets, making them the most variable component of the CAPEX.

Key Components and Cost Drivers

Key components and cost drivers of the BoP are described below.

- **Water purification system.** A water purification system transforms raw water into the ultrapure feed required by the electrolyzer stack. This process typically involves coarse filtration, activated carbon, softening or anti-scalant dosing, reverse osmosis for desalination when necessary, and final deionization or electro deionization to achieve the very low conductivity and total organic carbon levels demanded by OEMs. The main function of water purification is to prevent damage and performance losses in the stack by removing particulates, hardness, silica, and trace contaminants that can foul membranes, electrodes, and bipolar plates. Although essential, the water purification unit represents a small part of direct CAPEX (3–7 percent), making it a low-cost but critical subsystem within the BoP.

- **Hydrogen processing and storage.** The hydrogen compression system raises the pressure of hydrogen generated at near-atmospheric levels within the electrolyzer stack of atmospheric ALK systems, to intermediate pressures of around 30–40 bar in modern PEM and pressurized ALK systems. The gas is then further pressurized to meet the requirements of downstream applications such as storage, pipeline injection, or distribution, which can go up to several hundred bars for some applications. This system usually consists of multistage diaphragm or reciprocating compressors, along with inter- and after-coolers, dryers, filters, valves, and controls. By ensuring that hydrogen is delivered at the necessary pressure, it enables safe and efficient integration with downstream infrastructure. Compression is a significant cost component, accounting for around 10–16 percent of direct CAPEX (the share depends on the required delivery pressure and project specifications). Storage includes buffer vessels for low-pressure gas and, if required, larger intermediate storage in spherical vessels or a series of tubes (manifold). For large-scale, long-term storage, salt caverns are an option, but they involve high, site-specific development costs.

- **Gas-liquid separation and processing.** The hydrogen gas and liquid system is responsible for conditioning the raw hydrogen stream that exits the electrolyzer stack. This subsystem removes entrained water and electrolyte by separating the gas and the liquid, eliminates residual oxygen with catalytic deoxidation, and controls impurities and moisture with drying and filtration. It also manages pressure and flow, to ensure that the hydrogen meets safety and purity standards before entering compression, storage, or pipelines. It is a key component in the BoP and accounts for about 5–8 percent of direct CAPEX.

- **Thermal management system.** A thermal management system keeps the stack and process streams at safe and efficient operating temperatures while enabling temperature-based gas separation and drying steps. In a PEM electrolyzer, it typically includes radiators, coolers, chillers, and heaters, which manage the modest heat rise across the stack and provide the heating and cooling cycles required for hydrogen purification. This equipment represents a small share (approximately 4 percent) of direct CAPEX.

- **Electrical distribution equipment.** The electrical distribution infrastructure within a renewable hydrogen facility includes switchgear and cabling, including protective and control equipment, such as circuit breakers, disconnect switches, protection relays, and earthing systems, along with the power and control cables that interconnect key components (grid interface, transformers, rectifiers, electrolyzer stacks, and auxiliary systems like water treatment, cooling, and compression). Their primary function is to ensure safe operation, circuit isolation, and reliable power delivery across the facility. Although essential for system integrity and performance, switchgear and cabling typically represent only about 2–6 percent of direct CAPEX.

- **Civil works and buildings.** Civil works and buildings support the safe and compliant operation of a renewable hydrogen facility. They include earthworks, grading, structural foundations, equipment pads, pipe racks, drainage systems, fire protection infrastructure, fencing, access roads, and enclosed spaces such as control rooms, electrical rooms, and warehouses. In cases where electrolyzer stacks and auxiliary systems are not housed in modular containers, purpose-built structures may be necessary to accommodate equipment and ensure environmental protection. These elements are critical for enabling proper installation, operational safety, and regulatory compliance. The cost contribution of civil works to direct CAPEX varies significantly depending on the system configuration; it is typically lower for containerized outdoor installations and higher for custom-built facilities. As a result, the share of civil works in direct CAPEX ranges from single digits to low teens.

- **Mechanical BoP.** Mechanical BoP encompasses the piping, valves, and fittings that form the process fluid network within a renewable hydrogen facility. This system facilitates the delivery of purified water to the electrolyzer stacks, the extraction and routing of hydrogen and oxygen gases, and the integration of auxiliary units such as dryers, coolers, and gas-liquid separators. Flow control and isolation are achieved through devices including block, check, and pressure relief valves and other safety-critical components. Mechanical BoP includes ventilation and safety systems designed for hazardous environments, including hydrogen detection sensors, alarm systems, emergency shutdown logic, automatic shut-off valves, vent stacks for controlled gas dispersion, and forced ventilation systems (e.g., fans and ducts). These elements are essential for compliance with safety standards such as the National Fire Protection Association's NFPA 2 and the International Organization for Standardization's ISO 22734, which govern hydrogen handling and system integrity. Although mechanical BoP is vital for operational safety and process reliability, its share of direct CAPEX is often in the low single-digit percentage range. Its cost depends on whether the installation is containerized outdoors or housed within enclosed structures requiring enhanced safety provisions.

Share of balance of plant in direct capital expenditure and future cost reduction trajectories

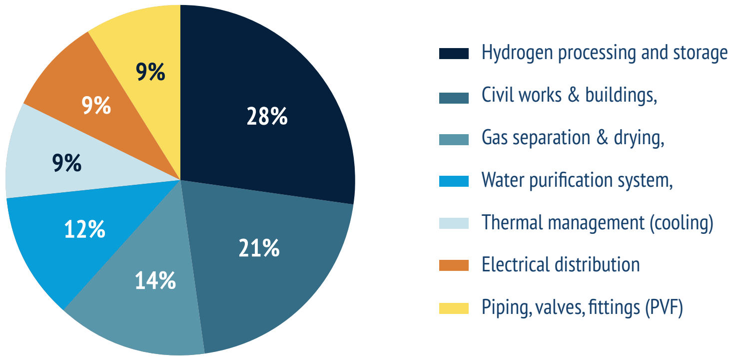
At commercial scale, the BoP can account for 30–60 percent of direct CAPEX, with the average around 40 percent. This range is influenced by the electrolyzer technology, system configuration, and site-specific engineering requirements (BNEF 2024; DOE 2024; IEA 2025; Ramboll 2023; Wood Mackenzie 2024). BoP cost structures are highly variable, reflecting differences in project design, integration complexity, and procurement strategies.

Understanding the cost bifurcation of BoP components is essential for optimizing the overall economics of hydrogen production projects. Aggregated data from multiple studies provide a useful approximation for evaluating component-level contributions.

Figure 2.6 presents a representative breakdown of BoP costs for a mature ALK system, assuming direct CAPEX of $1,000/kW and BoP-specific costs of $460/kW. These values are illustrative and intended solely to highlight the relative cost shares of key subsystems.

FIGURE 2.6

Representative breakdown of balance of plant costs



Source: World Bank staff.

The breakdown reveals that hydrogen processing and storage, along with civil works and buildings, account for 49 percent of total BoP costs. The other 51 percent is distributed among mechanical, electrical, and control infrastructure, each of which plays a critical role in enabling safe, reliable, and compliant operation of electrolysis facilities. Identifying the dominant cost drivers within the BoP helps project developers and engineers better target cost reduction strategies, improve system integration, and enhance overall project viability.

Unlike core electrolyzer stacks, for which breakthroughs in materials and electrochemistry can rapidly shift cost curves, BoP cost trajectories are shaped primarily by supply chain efficiency, component standardization, modularization, and economies of scale in both manufacturing and installation. As project capacities grow and design practices converge, cost optimization will increasingly depend on integrated engineering approaches, vendor consolidation, and streamlined procurement strategies to reduce complexity and enhance competitiveness. The following strategies aim to minimize bespoke engineering, shorten construction timelines, and improve predictability in project delivery.

- **Standardization and modularization.** Future cost reductions will be driven by the widespread adoption of factory-built skids and containerized systems, which significantly reduce on-site labor requirements; shorten commissioning timelines; and minimize the need for extensive piping, valves, and fittings. Modularization also enables parallel manufacturing and pretesting, reducing installation risks and improving quality control. Industry forecasts suggest that by 2030, modular BoP designs could cut installation costs by 15–25 percent, particularly for large-scale projects (Ramboll 2023).
- **Utility optimization and system simplification.** Innovations in utility design offer additional savings. Closed-loop thermal management systems can recover low-grade heat, reduce chiller size, and cut costs while improving energy efficiency. Right-sizing water purification systems with integrated recycling and polishing units prevents overspecification and lowers both CAPEX and OPEX. Operating stacks at higher outlet pressures reduces the need for large hydrogen compressors and dryers. Harmonizing pressure classes and deploying qualified nonmetallic piping where standards permit can further reduce material costs.

- **Instrumentation and procurement strategies.** Simplifying instrumentation by standardizing components lowers system complexity, reduces the size of spare-part inventories, and enhances maintainability. Early procurement of long-lead items such as transformers, switchgear, and specialized valves mitigates EPC overheads and reduces schedule delays. Future procurement models are expected to favor framework agreements with consolidated vendors, enabling bulk purchasing and reducing transaction costs.

Collectively, these strategies—modularization, utility optimization, pressure harmonization, and procurement streamlining—should reduce BoP costs. Although these improvements may appear incremental compared with stack-level innovations, their cumulative impact on total installed cost and project timelines is substantial. By reducing engineering complexity and accelerating deployment, BoP optimization will remain important for cost competitiveness in large-scale renewable hydrogen projects.

Composition of Direct Capital Expenditure

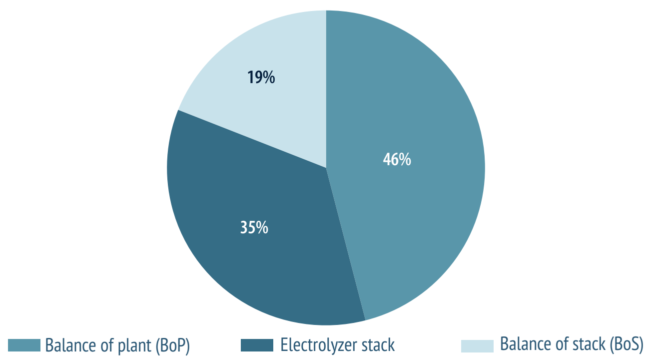
Understanding the typical distribution of capital across the three primary subsystems—electrolyzer stack, BoS, and BoP—is essential for effective budgeting, cost modeling, and strategic planning in hydrogen project development. Although actual cost proportions vary depending on project scale, technology selection, and site-specific design parameters, representative values can provide useful insights for comparative analysis.

Figure 2.7 presents an indicative cost allocation for a generic large-scale (greater than 100 MW) greenfield hydrogen project, based on a mature ALK electrolyzer configuration. For the purpose of illustration, direct CAPEX is assumed to be $1,000/kW.

The Figure shows that the BoP component contributes nearly as much to total direct CAPEX as the electrolyzer stack itself, underscoring its significance in overall system cost. The BoS, though smaller in share, includes critical subsystems such as the PCU, the largest cost element within the BoS. This illustrative breakdown underscores the fact that optimizing costs associated with the BoP and the BoS can yield meaningful reductions in total project expenditure. Such insights are valuable for guiding design decisions, procurement strategies, and cost-reduction efforts across the hydrogen value chain.

FIGURE 2.7

Breakdown of direct capital expenditure for an electrolysis system



Source: World Bank staff.

TABLE 2.2

Typical distribution of direct capital expenditure for a large-scale electrolysis system

<table>
<tr><th>SYSTEM TIER</th><th>COMPONENTS</th><th>TYPICAL PERCENTAGE OF DIRECT CAPEX</th><th>KEY COST DRIVERS</th><th>RISK MITIGATION INSTRUMENTS</th></tr>
<tr><td>Electrolyzer Stack</td><td>Cell stack (membranes, electrodes, plates, catalysts)</td><td>20–50</td><td>• Technology (PEM versus ALK)
• Prices of raw materials (iridium, nickel, titanium) Manufacturing scale
• Level of automation</td><td>• OEM performance warranties (efficiency, lifetime hours)
• Long-term service agreements
• Performance bonds
• Technology risk insurance</td></tr>
<tr><td rowspan="3">Balance of Stack (BoS)</td><td>Power conversion (rectifier/ transformer)</td><td>5–15</td><td>• Semiconductor and copper prices
• Efficiency requirements
• Custom design
• Often the largest line item after the stack</td><td rowspan="3">• EPC wrap for BoS integration
• Equipment warranties
• Grid interconnection guarantees
• Redundancy requirements
• OEM performance warranties (efficiency, lifetime hours)
• Long-term service agreements
• Performance bonds
• Technology risk insurance.</td></tr>
<tr><td>Electrolyte tank and electrolyte-gas separator</td><td>4–10</td><td>• Technically straightforward but labor intensive</td></tr>
<tr><td>Control system and instrumentation</td><td>1–3</td><td>• Level of automation
• Safety integrity level requirements</td></tr>
<tr><td rowspan="7">Balance of Plant (BoP)</td><td>Hydrogen compression and storage</td><td>10–16</td><td>• Highly variable
• Final delivery pressure
• Storage duration
• Technology (piston, diaphragm)</td><td rowspan="7">• EPC wrap for BoP integration
• Equipment warranties
• Grid interconnection guarantees
• Redundancy requirements</td></tr>
<tr><td>Water purification system</td><td>3–7</td><td>• Feedwater quality (tap, brackish, wastewater)
• Required flow rate</td></tr>
<tr><td>Gas separation and drying</td><td>5–8</td><td>• Required purity specifications
• Materials of construction (stainless steel)</td></tr>
<tr><td>Thermal management (cooling)</td><td>3–5</td><td>• System efficiency (waste heat)
• Ambient temperature
• Cooling method (air/ fluid)</td></tr>
<tr><td>Civil works and buildings</td><td>7–12</td><td>• Site preparation
• Local labor and material (concrete, steel) costs
• Weather protection needs</td></tr>
<tr><td>Electrical distribution</td><td>2–6</td><td>• Switchgear and cabling</td></tr>
<tr><td>Piping, valves, and fittings</td><td>3–5</td><td>• System layout complexity
• Materials (stainless steel for H2 lines)</td></tr>
</table>

Sources: World Bank staff analysis, based on IEA (2022), NREL H2A-Lite Model analysis (NREL 2024b), and industry benchmarks from EPC contractors.

Note: ALK = alkaline; EPC = engineering, procurement, and construction; H2 = hydrogen; OEM = original equipment manufacturer; PEM = proton exchange membrane.

Table 2.2 presents a detailed breakdown of all components contributing to direct CAPEX in large-scale hydrogen projects. The electrolyzer stack and BoP each typically account for around 40 percent of total direct CAPEX, with the BoS contributing around 20 percent. Within these categories, the electrolyzer stack, PCU, and hydrogen compression and storage systems are the most significant cost drivers.

Direct CAPEX requirements are highly sensitive to project-specific configurations. Where hydrogen compression or storage is not required—such as when hydrogen is consumed on-site or fed directly into a pipeline—overall CAPEX can be substantially lower than average. Given these differences, cost assessments must reflect the functional scope and integration strategy of each project.

Indirect Capital Expenditure

This section examines the critical, yet often underestimated, indirect costs associated with project development and execution, including the intellectual, managerial, and financial resources required to bring a project to fruition. These costs include engineering design and system integration, procurement and construction management, permitting and regulatory compliance, legal support, and financial structuring for the construction phase, all of which are essential for ensuring technical viability, regulatory alignment, and financial closure. These elements play a pivotal role in overall project delivery and risk mitigation.

Reducing indirect CAPEX requires coordinated policy support, including streamlined regulatory approvals, standardized technical guidelines, and the development of hydrogen hubs with shared infrastructure. In parallel, industry practices such as modular plant design and standardized execution frameworks are helping reduce complexity and cost. As the sector matures, further efficiencies are expected through improved developer capabilities, greater on-ground experience, and more effective procurement channels, contributing to a more predictable and optimized CAPEX structure.

Costs of Engineering, Procurement, and Construction

EPC costs, along with contingencies, typically account for 40–60 percent of indirect CAPEX, which itself may represent 25–40 percent of the total CAPEX for a renewable hydrogen project (BNEF 2024; DOE 2024; IEA 2025; Ramboll 2023; Wood Mackenzie 2024). The largest component of indirect CAPEX, EPC costs reflects the fee paid to the prime contractor responsible for delivering a fully functional facility. The scope and fee structure of the EPC contract are critical determinants of project risk, influencing both cost certainty and execution reliability.

First-of-a-kind and early commercial renewable hydrogen projects carry cost premiums that significantly raise EPC expenditures. These premiums arise primarily from two factors. First, EPC contractors often incorporate substantial risk margins to account for uncertainties related to cost overruns, schedule delays, and performance guarantees. Second, early-stage projects frequently require extensive custom engineering to accommodate integration with specific renewable power sources or offtaker facilities, which drives up design and system integration costs. As a result, final electrolysis system CAPEX can exceed initial vendor quotations by 20–50 percent, with the differential attributable largely to EPC fees, integration complexity, and contingency provisions.

For experienced developers or projects situated within established hydrogen clusters or industrial hubs, EPC costs tend to be more optimized, thanks to several compounding efficiencies. Experienced developers benefit from standardized design templates, streamlined procurement channels, and mature contractor relationships, which collectively reduce engineering and construction overheads. Projects located in hubs often leverage shared infrastructure, resulting in lower site preparation and utility integration costs. These settings also enable better coordination with local authorities and regulatory bodies, accelerating timelines and reducing risk premiums. As a result, EPC costs for such projects typically exhibit lower variability and improved cost predictability than stand-alone or first-of-a-kind installations.

Reducing EPC costs in renewable hydrogen projects requires a combination of strategic policy support and evolving industry practices. Governments can play a catalytic role by facilitating the development of hydrogen hubs with shared infrastructure—such as grid access, water supply, and permitting frameworks—which significantly lower site-specific engineering and construction costs. Streamlined regulatory approvals, standardized technical guidelines, and incentives for local manufacturing further contribute to cost optimization.

A growing number of experienced developers are bypassing traditional EPC contracts altogether, opting instead to manage procurement and construction in-house. This approach allows for greater control over design, scheduling, and cost management, particularly in familiar geographies or repeat project configurations. When supported by enabling policies and institutional capacity, both hub-based development and direct execution models can potentially improve cost efficiency and accelerate deployment timelines.

Freight Costs

Freight costs differ significantly across electrolyzer technologies, because of variations in size, weight, and transportability. PEM stacks are substantially more compact than ALK stacks for the same hydrogen output, enabling shipment in standard containerized units. As a result, transport costs for a 10 MW PEM package typically range from $100,000 to $200,000 (about 1–3 percent of equipment value). ALK systems consist of larger and heavier stacks and skids that often exceed standard container dimensions. They require specialized handling and oversized freight, increasing transport costs to roughly $150,000–$300,000 (around 4–10 percent of equipment value). Logistics expenses are higher for long-distance maritime routes—such as deliveries to Latin America or Southern Africa—and for inland transport legs, which may require additional road permits or escorts. In some markets, the limited availability of heavy-lift cranes or oversized-handling equipment can impose additional charges, adding to overall project CAPEX.

Other Indirect Capital Expenditures

Other expenses borne directly by the project developer (the owner) are separate from the EPC contract price. They include the following:

- Financing costs. Financing costs are the costs associated with raising debt and equity for the project. They include the following:
  - *Financing fees.* Fees paid to lenders and underwriters for arranging debt.
  - *Legal and advisory fees.* Fees paid for drafting loan agreements and conducting due diligence.
  - *Interest during construction.* This represents the interest accrued on debt during the construction phase, typically capitalized into total project CAPEX. For large-scale projects with construction timelines of two to three years, interest during construction can amount to tens of millions of dollars, making it one of the largest cost elements. In addition, projects require development CAPEX to cover preconstruction activities such as permitting, engineering, legal services, and technical studies (Box 2.2). Working capital is essential during early operations to fund operational expenses, meet lenders' liquidity requirements, and manage inventory.
- Transaction advisory. Fees paid for legal counsel to draft and negotiate EPC, operation and maintenance, and offtake agreements; secure land rights; and structure project finance documents.
- Permitting. The cost of securing all necessary local, state, and federal permits, including environmental impact assessments, land use permits, air and water permits, and hydrogen-specific safety reviews. These costs are highly location dependent and can be significant, particularly in regions with stringent regulatory frameworks.
- Insurance during construction. Policies for builder's risk, liability, and delay in start-up.
- Owner's team costs. Salaries, overhead, and expenses for the owner's project managers, engineers, and other staff overseeing the EPC contract.
- Spare parts and initial catalysts/chemicals. The initial inventory of critical spare parts and consumables required for start-up.
- Commissioning and start-up costs. Costs of the team and utilities required to commission the plant, excluding the EPC contractor's scope.

BOX 2.2

THE NEED FOR WORKING CAPITAL AND DEVELOPMENT CAPITAL EXPENDITURE

Clean hydrogen projects typically require substantial up-front and ongoing financial commitments in the form of both working capital and development expenditure (DEVEX), which covers preconstruction activities such as permitting, engineering, legal services, and technical studies. Working capital is essential during initial operations to cover operational expenses, meet lenders' liquidity requirements, and manage inventory. Estimates vary by project size, offtake agreements, and plant design, but the US Department of Energy suggests maintaining a working capital of 5–10 percent of total capital costs. The National Renewable Energy Laboratory (NREL 2024a) recommends around three months of operational expenses.

On the asset side, working capital needs are influenced by offtake payment terms; operational buffers for industrial gases (e.g., hydrogen, nitrogen); insurance coverage; operation and maintenance clauses for spare parts availability; and lender requirements such as debt service or major maintenance reserve accounts. On the liabilities side, drivers include the payment terms of power purchase agreements; fixed monthly expenses (payroll, taxes, regulatory contributions); and procurement conditions for other inputs.

DEVEX typically accounts for 3–8 percent of total project costs. Both working capital and DEVEX represent critical financial components that must be accurately forecasted to ensure liquidity, compliance with lender covenants, and timely project execution.

Conclusion

The economics of renewable hydrogen production are shaped by direct CAPEX, which covers electrolyzer stacks, BoS, and BoP, and indirect CAPEX, which includes EPC fees, financing, permitting, and development costs. Near-term cost reduction strategies focus on modularization, supply chain optimization, and integrated delivery models.

Long-term competitiveness ultimately hinges on scaling deployment. Learning curves demonstrate that each doubling of cumulative installed capacity reduces electrolyzer costs by 14–17 percent, underscoring the critical role of manufacturing scale-up and technology innovation (Box 2.3). Projections suggest that achieving 70 GW of electrolyzer capacity by 2030 could enable the first major cost halving for ALK and PEM technologies, with further reductions driven by standardization and supply chain maturity.

BOX 2.3

INSIGHTS FROM LEARNING CURVES

Learning curves describe how technology costs decline as deployment scales. They are typically expressed by a learning rate: the percentage reduction in cost for each doubling of cumulative installed capacity.

Learning curves are useful for anticipating long-term cost trends, but they capture correlation rather than causality. Cost trajectories also depend on factors such as commodity prices, supply chain disruptions, innovation breakthroughs, and manufacturing strategies. Outcomes can be very sensitive to specific input assumptions. For this reason, analysts emphasize transparency and caution when applying learning rates to long-term forecasts.

Glenk et al. (2023) provide one of the most comprehensive empirical assessments of electrolyzer learning. They find that over the past two decades, each doubling of cumulative capacity reduced system prices by 14–17 percent (15 percent for alkaline [ALK], 14 percent for proton exchange membrane [PEM], 17 percent for solid oxide electrolyzer cell [SOEC]) and lowered electricity consumption by about 2 percent. Using a Europe-only data set, Galletti et al. (2025) identify higher learning rates (22–32 percent). Their analysis may ignore spillover effects from learning elsewhere, however, and may therefore be too optimistic.

To illustrate the implications of these learning rates, consider global deployment and capital expenditure levels at the end of 2024:

- ALK: 1,300 MW installed; $2,000/kW
- PEM: 720 MW installed; $3,000/kW
- SOEC: 3 MW installed; $6,000/kW

Reaching a global average cost of $800/kW would require:

- ALK: About 7 doublings, leading to about 83 GW cumulative capacity
- PEM: About 9 doublings, leading to about 184 GW cumulative capacity
- SOEC: About 12 doublings, leading to about 6 GW cumulative capacity

Reaching this global average would require cumulative investment across all technologies of about $270 billion under Glenk's learning rates.

The investment needs can be further broken down by technology. Using Glenk's learning rates to assess cost reduction potential from scale effects suggests that halving total system costs for ALK technology, from $2,000 to $1,000/kW, would require around 20 GW of cumulative deployment and investments of about $27 billion. Achieving another halving (to $500/kW) would require roughly 660 GW of installed capacity and an additional $380 billion in investments.

BOX 2.3 *(CONTINUED)*

For PEM technology, Glenk's learning rates indicate that a first halving of system costs, from \$3,000 to \$1,500/kW, could be achieved with about 11 GW of cumulative capacity and \$21 billion in investments. A second halving (to \$750/kW) would require around 370 GW and an additional \$290 billion in investments.

These estimates underscore how rapidly costs could fall with sufficient global deployment. According to the Hydrogen Council (2025), the project pipeline includes 5–7 million tons/year of renewable hydrogen by 2030, equivalent to roughly 70 GW of electrolyzer capacity after accounting for attrition. If realized, this scale would be adequate to achieve the first major cost halving for both ALK and PEM technologies before 2030, with further reductions expected from innovation, standardization, and improved manufacturing logistics.

The CAPEX associated with green hydrogen production facilities demonstrates substantial variability, arising from a complex interplay of geographical, regulatory, technological, and project-specific factors such as size. Cost outcomes differ substantially between first of a kind developments and subsequent commercial scale deployments and are further conditioned by the effectiveness of permitting processes, compliance mechanisms, and the broader policy environment. In addition, technical design requirements, such as the specified hydrogen purity, delivery pressure, and on-site storage configuration, exert a significant influence on total system costs and associated engineering complexity.

Within this expenditure profile, electrolyzer stacks, while fundamental to overall system performance, typically constitute only 20–50 percent of direct CAPEX in contemporary large-scale ALK and PEM installations. BoS and BoP components frequently represent the predominant contributors to direct CAPEX, jointly accounting for approximately 50–80 percent depending on technology selection, site characteristics, and integration requirements. Installation and EPC activities, classified as indirect CAPEX, often comprise the single largest portion of total installed cost, generally in the range of 40–50 percent, particularly for projects involving extensive civil works, complex grid or process integration, or stringent infrastructure requirements.

Pronounced regional disparities in electrolyzer equipment pricing continue to be observed across global markets. ALK systems manufactured in leading East Asian industrial centers typically exhibit domestic costs in the range of approximately \$270–\$280/kW, rising to around \$350/kW for export markets. In contrast, comparable ALK systems produced in Europe or the United States generally cost around \$800/kW. When broader installation requirements, such as logistics, EPC services, civil works, and auxiliary system integration are incorporated, installed ALK costs in emerging markets generally fall between \$800 and \$1,200/kW for East Asian–manufactured systems and \$1,200 and \$1,800/kW for units manufactured in Europe or the United States, with smaller projects typically positioned toward the upper end of these ranges.

PEM electrolyzers continue to command a substantial cost premium due to their reliance on platinum group metals, including iridium and platinum. While the smaller spatial footprint of PEM systems can reduce certain installation-related overheads, this advantage only partially offsets the higher material and component costs. As a result, complete PEM systems sourced from major East Asian suppliers commonly fall within the $700–$1,000/kW range, compared with approximately $1,000–$1,600/kW for their European counterparts. But lower cost cases exist also for PEM, comparable with ALK prices: using standardized plant architecture at the Infinium Roadrunner project, Electric Hydrogen is constructing a PEM electrolyzer plant in the U.S. with total installed project capital cost of less than 1000 USD/kW (IEA, 2025). Fully installed PEM projects in emerging markets typically range from $1,850 to $2,500/kW, depending on site conditions, integration requirements, and project scale. Overall, these variations reinforce the absence of a uniform benchmark for electrolyzer CAPEX and highlight the importance of undertaking context-specific, project-level cost assessments when evaluating green hydrogen deployment pathways.

Reducing CAPEX for renewable hydrogen projects requires a two-pronged approach: (1) short-term optimization of both direct and indirect cost components through engineering and procurement efficiencies; and (2) long-term cost declines through accelerated deployment to unlock learning effects. Together, these dynamics will position renewable hydrogen as a cost-competitive and scalable pillar of the global clean energy transition.

Operational Expenditure

CAPEX is the primary consideration during the initial investment phase. But the long-term financial viability and bankability of projects are fundamentally influenced by the precision of OPEX forecasting and the management of OPEX. This section presents a detailed assessment of the OPEX associated with renewable hydrogen electrolysis facilities. To provide a more granular understanding of cost drivers and their implications for project economics, it categorizes OPEX into fixed and variable components.

OPEX plays a pivotal role in project implementation, particularly given the significant impact of electricity consumption and stack replacement on the LCOH throughout the asset's life cycle. Electricity constitutes the largest share of the LCOH in renewable hydrogen production, positioning the availability of low-cost, renewable electricity as a critical factor in investment decision-making.

Fixed Operational Expenditure

Fixed OPEX comprises costs that are incurred regardless of the plant's operational output. It includes the expenses required to maintain a facility in a state of operational readiness, ensure safety and compliance, and perform scheduled upkeep. These costs are generally predictable and can be budgeted annually.

Labor: Operation and Maintenance Staff

The skilled personnel required for the operation and maintenance of the electrolysis facility represent a substantial fixed expenditure. Staffing requirements do not scale linearly with plant capacity; they exhibit a stepwise progression, reflecting operational thresholds beyond which additional personnel are necessary. When estimating labor needs, key considerations include the following:

Typical requirements. A large-scale facility with a capacity exceeding 100 MW typically requires a dedicated team of 10–20 highly skilled professionals working in rotating shifts to maintain continuous 24/7 operations. Key roles within this team include control room operators, who oversee real-time system performance; maintenance technicians, who are responsible for equipment upkeep; instrument engineers, who ensure accurate monitoring and calibration; and a plant manager, who oversees overall operations and coordinates across departments.

Cost drivers. Labor costs for operating a hydrogen production facility can vary significantly depending on several factors, including location, local labor market conditions, union regulations, and the degree of automation. Facilities with high levels of automation and advanced predictive maintenance systems can operate with a more streamlined workforce, reducing staffing requirements. According to industry benchmarks from the National Renewable Energy Laboratory's H2A model, a highly automated plant may require only two to four personnel per 100 MW of capacity, with labor costs adjusted based on regional wage structures and employment standards.

Financial impact. For a project in a developed market, labor costs (salaries, benefits, training) can easily exceed $1.5 million a year for a 100 MW plant.

Maintenance contracts

Preventive maintenance is crucial for maximizing system availability and preventing catastrophic failures. It is often managed through structured service agreements with the OEMs or specialized third-party service providers. Contracts cover factors that include:

Scheduled maintenance. Scheduled maintenance encompasses routine, time-based activities aimed at ensuring the continued safe and efficient operation of the electrolysis plant. These tasks typically include periodic inspections; calibration of instrumentation and control systems; servicing of mechanical components, such as pumps and compressors; and replacement of consumables, such as filters. Maintenance intervals are generally defined by operational best practices and OEM recommendations; they are usually executed quarterly, semiannually, or annually. For electrolyzer facilities, scheduled maintenance is essential for preserving system integrity, minimizing downtime, and ensuring compliance with performance warranties and safety standards.

Preventive maintenance. Preventive maintenance involves scheduled, proactive inspections and the replacement of components based on predefined operational thresholds—typically running hours or cycle counts—as specified by the OEM. These activities are more intrusive than routine checks and are designed to mitigate the risk of unexpected failures, optimize equipment performance, and extend asset life. Preventive maintenance is a critical element of reliability-centered operations and contributes to the fixed OPEX profile of electrolysis facilities.

Cost structure. Maintenance contracts are typically structured as annual service agreements, with costs ranging from 1.0 percent to 2.5 percent of the capital value of the covered equipment (NREL 2024a; DOE 2024). For critical BoP components, such as compressors, OEM service contracts are standard practice and often represent a significant portion of fixed OPEX.

Insurance and Taxes

Insurance and taxes are statutory and risk mitigation costs required for any industrial operation. They include the following:

Property and liability insurance. Property and liability insurance covers physical damage to electrolysis assets as well as protection against third-party claims arising from operational incidents. Insurance premiums are typically calculated based on several key factors, including the insured value of the facility (linked to CAPEX); the inherent risk profile of the electrolysis technology deployed; and site-specific considerations such as location, environmental exposure, and regulatory context. For large-scale hydrogen facilities, property and liability insurance represents an important fixed cost component. Its structure may vary depending on the insurer's assessment of operational hazards and mitigation measures in place.

Delay in start-up (DSU) and business interruption insurance. DSU and business interruption insurance are designed to protect project stakeholders against revenue losses resulting from extended unplanned outages or delays in commissioning. Such policies are particularly important for electrolyzer-based renewable hydrogen facilities, because of their high capital intensity and sensitivity to operational uptime. Coverage typically includes compensation for lost income during periods when the facility is unable to operate because of insured events such as equipment failure, grid disruptions, or force majeure. For project financiers and investors, DSU and business interruption insurance are essential components of the overall risk management framework, directly affecting project bankability and financial close.

Environmental impairment liability insurance. Environmental impairment liability insurance covers potential environmental damage arising from the operation of a renewable hydrogen production facility. Covered risks are associated with accidental releases of hazardous substances, contamination of soil or groundwater, and emissions that may breach regulatory thresholds. Given the use of high-pressure systems; chemical feedstocks (e.g., water treatment agents); and large-scale energy infrastructure in electrolyzer-based hydrogen production, environmental liability is a concern. Coverage terms are typically affected by the facility's location, proximity to sensitive ecosystems or water bodies, and the robustness of its environmental management systems. For developers and operators, this type of insurance is a key component of compliance and risk mitigation strategies. It is often required by lenders and regulatory authorities to ensure long-term environmental stewardship.

Local taxes. Local authorities impose levies and municipal business taxes on hydrogen production facilities, including land use taxes, infrastructure development charges, and business operation fees. These taxes vary depending on the jurisdiction and the regulatory framework of the project location. For renewable hydrogen facilities, particularly those occupying large land parcels or integrated within industrial zones, these taxes represent a recurring fixed cost. The magnitude of local taxation depends on factors such as facility size, assessed property value, local economic policies, and any applicable incentives or exemptions for clean energy infrastructure. Accurate estimation and compliance with local tax obligations are essential for long-term financial planning and regulatory alignment.

Annual insurance premiums for renewable hydrogen production facilities can range from 5–10 percent of the total insured asset value (World Bank 2024). High premiums reflect the emerging nature of electrolysis-based hydrogen technologies and the associated risk perceptions held by insurers. Factors contributing to elevated premiums include limited long-term operational data, evolving safety standards, potential hazards related to high-pressure hydrogen systems, and uncertainties around equipment reliability and supply chain maturity. Site-specific risks—such as grid stability, environmental exposure, and regulatory compliance—also influence underwriting decisions. As the industry matures and more performance data become available, insurance costs are likely to stabilize, improving overall project economics and bankability.

Debt Interest and Equity Payments

Debt interest and equity payments depend on the project's capital structure. They remain relatively stable over the plant's operational life.

Debt servicing typically involves periodic interest payments; equity financing requires returns to shareholders through dividends or profit-sharing arrangements. The scale of these costs is largely determined by the weighted average cost of capital (WACC), which reflects the blended cost of debt and equity adjusted for project-specific and regional risks. In jurisdictions with heightened political, regulatory, or currency volatility, risk premiums drive up both interest rates and equity return expectations, increasing the WACC. For emerging technologies such as renewable hydrogen, hurdle rates are generally higher because of lower leverage—often close to parity between debt and equity—combined with uncertainties in technology performance, market adoption, and long-term revenue streams. A high WACC significantly raises financing costs, reducing net present value and challenging commercial viability (Box 2.4). Risk mitigation strategies, including long-term offtake agreements, government incentives, and blended finance models, are essential to manage these fixed costs and enhance financial sustainability and competitiveness in the renewable hydrogen sector.

BOX 2.4

HOW DO FINANCING COSTS AFFECT THE CHOICE OF ELECTROLYZER?

Financing costs vary widely, by country and by project. Investors want to see a return that reflects the perceived risk.

Clean hydrogen projects are more risky than pure renewable power projects, because of offtake agreement risks, regulatory uncertainty, and unfavorable unit economics compared with carbon-intensive alternatives. As a consequence, the costs of financing are higher. Given the volatility of project cashflow, the share of total costs financed by senior debt is lower, leaving more costly equity to play a larger role. Even with low leverage, senior debt financing is more expensive, because project risks are higher.

Clean hydrogen projects in emerging markets and developing countries face higher financing costs than similar projects elsewhere, mainly because the perceived country risk is higher (OECD and World Bank 2024). Risk mitigation instruments can be applied to mitigate some aspects of country risk, but at an associated cost. Whether their use increases the expected returns to the project financers depends on each country's context and each project's cashflow.

The weighted-average cost of capital (WACC) is a measure of a project's cost of financing. The World Bank assessed clean hydrogen projects at different development stages across 10 country settings. The range for the projects' WACC in nominal dollars ranged from 8.9 to 18.9 percent (Table B2.4.1). Projects with lower financing costs favor the use of costlier but more efficient or flexible electrolyzers; projects with higher financing costs favor cheaper but less sophisticated electrolyzers.

TABLE B2.4.1

Cost of financing hydrogen electrolyzer projects without deployment of risk mitigation instruments in selected countries (%)

COUNTRY	WEIGHTED AVERAGE COST OF CAPITAL	PRE-TAX COST OF DEBT	LEVERAGED COST OF EQUITY	AVERAGE DEVELOPMENT PREMIUM	CORPORATE INCOME TAX RATE
Brazil	10.7	11.3	15.4	1.7	34.0
Chile	8.9	7.5	14.1	3.0	27.0
Colombia	11.2	12.9	15.4	1.0	35.0
Egypt, Arab Rep.	14.6	11.1	23.6	2.5	22.5
India	9.5	8.2	15.1	2.0	30.0
Mauritania	18.9	14.4	30.9	3.5	25.0
Morocco	12.2	11.2	17.2	3.5	20.0
Namibia	12.7	11.5	19.8	3.3	30.0
South Africa	10.9	9.2	17.3	3.0	27.0
Tunisia	15.5	12.6	23.6	4.0	20.0
Min.	**8.9**	**7.5**	**14.1**	**1.0**	**20.0**
Max.	**18.9**	**14.4**	**30.9**	**4.0**	**35.0**

Source: World Bank analysis.
Note: Data were calculated for specific projects. Data do not account for tax credit benefits in case of profitable projects. The weighted-average cost of capital assumes a 60/40 debt-to-equity ratio.

Variable Operational Expenditure

Variable OPEX are costs that scale directly with the level of plant operation (e.g., hours of operation, volume of hydrogen produced). These costs are directly tied to the consumption of materials, components, and utilities (water and electricity).

Energy Consumption

In electrolysis-based renewable hydrogen production, electricity is the primary feedstock, driving the water splitting process. It sometimes accounts for up to 80 percent of total production costs. Variations in electricity tariffs, grid access charges, and renewable energy availability directly influence OPEX; intermittency challenges underscore the importance of securing long-term access to low-cost, reliable, and clean power.

Electrolyzer efficiency and current density are critical performance metrics. Higher efficiency reduces electricity consumption and OPEX; higher current density increases hydrogen output per unit area, enabling smaller stack sizes and lower capital costs. However, elevated current densities also raise ohmic losses, reducing efficiency and increasing energy demand. Manufacturers and developers must balance these trade-offs based on site-specific conditions, including electricity pricing, supply variability, and spatial constraints. PEM systems offer high current densities and compact designs but have higher CAPEX; ALK systems operate at lower current densities with greater efficiency and lower up-front costs. These parameters also affect system sizing, land use, and integration complexity, which are especially relevant for constrained sites like ports and industrial clusters.

For investors and lenders, efficiency assumptions are central to assessing project bankability. They affect electricity consumption forecasts, LCOH modeling, and financial resilience. Given electricity's dominant share in OPEX, even modest efficiency gains can significantly improve returns; underestimating degradation risks may lead to overoptimistic projections and long-term underperformance. Factors to consider include the following:

Consumption. The energy demand of a renewable hydrogen production facility is determined primarily by electrolyzer efficiency, which is typically 50–55 kilowatt-hours per kilogram of hydrogen (kWh/kgH2) for commercial PEM and ALK systems. A plant producing 1 million tons (Mt) of hydrogen a year at around 90 percent capacity factor consumes around 50,000 gigawatt-hours (GWh) of electricity consumption a year. Meeting this demand exclusively through renewable sources requires significant upstream generation capacity, which varies by region depending on local capacity utilization factors (CUFs). In southern Chile, where onshore wind CUFs can reach 65 percent, the required installed capacity would be around 8.75 GW; in Germany, with a CUF of 35 percent, the same plant would need around 16.5 GW. These Figures highlight the immense scale of renewable infrastructure needed to support green hydrogen production, along with associated investments in land, grid integration, and energy storage to manage intermittency and ensure continuous operation. Such energy requirements have direct implications for project economics, influencing CAPEX, permitting complexity, and long-term asset valuation. They also underscore the importance of strategically siting projects and securing long-term power purchase agreements (PPAs) to ensure affordable and reliable electricity supply.

Cost structure. Electricity costs for renewable hydrogen production are determined primarily through long-term PPAs, which are essential for securing predictable and bankable pricing. As of 2023, levelized PPA prices for solar and wind projects were \$20–\$60 per megawatt-hour (MWh), depending on regional resource quality and market conditions. The actual cost depends heavily on the electrolyzer's capacity factor (CF) and the sizing of the renewable energy system. Higher CFs require proportionally larger renewable capacity combined with energy storage to ensure continuous operation, especially in regions with lower solar or wind CUFs. Optimizing the match between electrolyzer load and renewable generation—through strategic siting, hybrid resource integration, and well-structured PPAs—is critical to minimizing electricity costs and achieving competitive LCOH.

Financial impact. With a baseline electricity price of \$50/MWh and an electrolyzer efficiency of 52 kWh/kgH2 produced, the electricity cost component alone amounts to around \$2.60/kg. Even a relatively small increase of \$10/MWh in the PPA rate can raise the LCOH by about \$0.52/kg. An economically viable LCOH can still be achieved despite significant up-front capital investment if the project benefits from an optimized capital structure and operates the electrolyzer at a high CF. High electricity prices make it virtually impossible to achieve a low LCOH, no matter how efficient or well financed the system is.

Degradation of the Electrolyzer Stack

Degradation is the second-most-significant variable OPEX item and a primary source of financial concern. The electrolyzer stack degrades over time, losing efficiency and eventually requiring refurbishment or replacement to maintain nameplate capacity and efficiency. Degradation significantly affects project bankability and long-term returns by increasing electricity consumption per kilogram of hydrogen and raising maintenance costs as a result of more frequent component replacements, such as membranes, catalysts, and seals. These impacts cascade into life-cycle cost models, production forecasts, and financial metrics like the internal rate of return and the debt service coverage ratio. Stack replacement alone accounts for up to 15 percent of total CAPEX. Cost factors to consider include the following:

Stack degradation. Electrolyzer degradation results primarily from the gradual wear and tear of core stack components caused by operational stresses. The specific causes and rates of degradation vary across electrolyzer technologies. ALK electrolyzers exhibit the lowest degradation rates among commercial options; PEM electrolyzers tend to degrade more quickly. For SOEC and AEM technologies, data are still limited, but the Electric Power Research Institute (EPRI 2022) suggests that their degradation rates may be even higher than those of ALK and PEM at this stage of development.

Replacement cycles. Industry standards typically call for stack replacement when key performance indicators fall below contractual thresholds—such as a decline in hydrogen purity or efficiency or a 10–15 percent increase in operating voltage. For ALK electrolyzers, this replacement is generally expected after 60,000–100,000 hours of operation, which equates to about 7–12 years at a 90 percent CF. Reaching this operational lifespan depends on maintaining optimal operating conditions and adhering to rigorous maintenance protocols throughout the system's life.

Financial impact. Replacing an electrolyzer stack often costs 30–60 percent of the original stack CAPEX. This major recurring capital expense must be carefully planned for, through operational cash flows or by setting aside funds in a dedicated sinking fund. Extending the operational life of stacks is one of the most critical areas of research and development for driving down the LCOH.

Consumables

Electrolyzer operations require a range of consumable materials in addition to water and electricity. They may be consumed directly by the electrolyzer or by supporting systems and ancillary equipment. Such materials need to be replenished periodically to ensure smooth and efficient functioning. The type and cost of these consumables vary significantly depending on the specific electrolyzer technology in use.

Consumables include the following:

Electrolytes. In an ALK electrolyzer, the electrolyte—typically a potassium hydroxide solution—gradually accumulates impurities. It requires periodic purging and replacement to maintain system performance and longevity. Potassium hydroxide is only moderately expensive, but its handling and disposal involve specific safety and environmental considerations, making proper management essential for efficient and compliant operations.

Membranes. PEMs are engineered for long operational life, but they are still susceptible to degradation, from mechanical stress, chemical wear, and exposure to harsh operating conditions. Occasional replacement is necessary to maintain system performance and reliability. The frequency and cost of membrane replacement vary, depending on operating conditions and maintenance practices. Membranes typically account for about 20 percent of the total cost of an electrolyzer stack (see also Box 2.1).

Other consumables. Other consumables essential for sustained operation include deionized water, gas purification filters, lubricants, and chemical agents used for system cleaning and conditioning, all of which require regular monitoring and replenishment to maintain optimal performance:

- **Filters** are used across water, air, and gas streams to remove particulates and contaminants. They require regular inspection and replacement to maintain system integrity and prevent fouling or damage to sensitive components.
- **Desiccants** are used in gas drying units to remove moisture from hydrogen or oxygen streams. Over time, they lose their effectiveness and must be replaced to ensure gas purity and prevent corrosion or downstream issues.
- **Cooling system chemicals** include antifreeze agents and corrosion inhibitors, which help regulate temperature and protect cooling circuits from scaling and degradation. Periodic replenishment and monitoring are essential to maintain thermal efficiency and equipment longevity.

Although the cost of individual consumables in an electrolyzer setup—such as filters, desiccants, and cooling system chemicals—is relatively low, their cumulative annual expense can become significant, especially in large-scale operations. Recognizing this, the US Department of Energy, through its multiyear program plan, identifies consumable costs as a key performance indicator and has set specific targets to reduce their impact on the LCOH.

Water

Water is a critical input for the production of renewable hydrogen, used primarily for two functions: (1) as the feedstock for the electrolysis process and (2) as a medium for cooling. The volume of water required is relatively low compared with other industrial processes. But water withdrawal can strain local resources, especially in arid or water-stressed regions, and consumption reduces the volume of water returned to the ecosystem. If not properly treated, wastewater discharge can reduce water quality and local biodiversity. Therefore, although water may not heavily affect financial metrics, its responsible management is essential for sustainable and environmentally sound hydrogen production.

Water use depends on the electrolyzer water quality requirements, the cooling technology that is applied, and the source of the raw water. The implications of those aspects are elaborated in Box 2.5.

Cost drivers. The primary cost associated with water use in hydrogen production is the electricity required for purification. Raw water, whether sourced from potable water, groundwater, surface water, or seawater, must be treated to meet the high purity standards required for electrolysis. This purification process typically involves filtration, deionization, and in some cases desalination, all of which consume energy. Water treatment can add around 0.5-2.0 percent to the plant's total electrical load, depending on the quality of the input water and the complexity of the purification process.

Impact on the LCOH. Despite its operational importance, water contributes only marginally to the LCOH. Estimates suggest that water-related costs amount to around \$0.02–\$0.05/kg of hydrogen, representing less than 1 percent of the LCOH.

BOX 2.5

FACTORS BEHIND THE WATER REQUIREMENTS OF HYDROGEN ELECTROLYSIS SYSTEMS

The stoichiometric water requirement for hydrogen production via electrolysis is approximately 9 liters of water per kilogram of hydrogen produced, regardless of the electrolyzer technology employed. In practice, however, total water consumption in an electrolysis system is significantly higher. This is due to water losses incurred during treatment processes needed to meet electrolyzer feedwater quality specifications, water consumption associated with system cooling, and the overall complexity of water treatment, which is strongly influenced by the quality of the raw feedwater source. These factors are discussed in more detail below.

Water quality requirements

Water quality and treatment are critical determinants of the operational efficiency, cost structure, and long-term sustainability of hydrogen production facilities. In particular, the performance of reverse osmosis (RO) systems varies significantly depending on feedwater characteristics and the purity requirements associated with different electrolysis pathways. RO is the most widely deployed purification and water desalination technology today. A pressure-driven water separation process that removes dissolved salts and impurities from raw water before it is supplied to electrolysis systems, it typically achieves 95 to 99 percent salt rejection and serves as the primary step for reducing water conductivity prior to final purification.

In order to ensure the consistent production of ultrapure water, recovery rates are often intentionally reduced, sometimes to as low as 25–50 percent, particularly in applications with stringent purity requirements (Lin et al. 2024). This is the case for PEM electrolysis, which requires ultrapure water with conductivity levels below 0.1 μS/centimeter (cm). In contrast, alkaline water electrolysis (AWE) is less demanding, tolerating conductivity levels of approximately 1–5 μS/cm. Despite these differences in water quality requirements, both technologies typically rely on similar treatment processes, including RO and particle filtration, to reliably meet their respective standards. Therefore, water consumption due to a reduced water recovery rate is similar for both technologies as well.

Water cooling technologies

Cooling water requirements for hydrogen production via electrolysis vary significantly depending on the cooling technology used, hydrogen production plant scale, energy source, and climatic conditions. Although cooling water quality requirements are less stringent than those for electrolyzer feedwater, a certain level of treatment is necessary depending on the raw water source and the cooling technology selected. As a result, the choice of cooling approach is closely tied to site-specific factors, including water availability, environmental constraints, plant location, and project scale. CS-N0W (2024) discusses the three cooling technologies most commonly considered for electrolysis systems as outlined below.

BOX 2.5 *(CONTINUED)*

Once-through water cooling involves circulating water through the system a single time before discharging it back to the source without recirculation. While this approach is technically simple, it requires very large water withdrawals, even for relatively small installations. Due to these high water demands and the potential for adverse ecological impacts associated with elevated discharge temperatures, single-pass cooling is generally unsuitable for inland locations with water-constrained conditions. It may, however, be considered for seawater use in offshore or coastal hydrogen electrolysis facilities operating at large scale, where water availability is abundant and thermal impacts can be more effectively managed.

Evaporative cooling systems rely on the latent heat of vaporization to dissipate process heat. Although a portion of water is lost through evaporation and blowdown, total water withdrawals are significantly lower than those associated with once-through cooling. As dissolved solids concentrate in the recirculating water, additional pretreatment is required to maintain system performance and prevent scaling or fouling. Evaporative cooling is a flexible and widely applicable solution, suitable for hydrogen production facilities ranging from a few megawatts to large multi-megawatt installations, but with a larger physical footprint at higher capacities.

Air cooling, or dry cooling, eliminates water use entirely by relying on ambient air for heat rejection. However, dry cooling systems require large, air-cooled heat exchangers, extensive finned surface areas, substantial structural steel, and high-capacity fans, resulting in significantly higher capital costs than evaporative cooling. In addition, the large number of fans increases electricity consumption, leading to higher operating costs compared with evaporative systems (Ellersdorfer 2025).

Water source implications

The selection of a water source for hydrogen production, whether potable water, surface water, groundwater, or seawater, has implications for water treatment complexity and water recovery rates. Each source differs significantly in its initial water quality, which directly determines the number of treatment steps required to meet the purity standards needed for electrolysis, ASTM Type II in the case of PEM electrolyzers. As treatment intensity increases, water losses rise and additional costs are incurred. The differences in the water treatment processes due to the source of water are discussed in CS-N0W (2024) and summarized below.

Potable water represents the least demanding option from a treatment standpoint. No treatment is required when used for single-pass or evaporative cooling. For PEM feedwater standards, potable water undergoes membrane filtration, de-chlorination, and a single pass of RO. Afterwards, a final polishing step using electrodeionization (EDI) or ion exchange is required to remove residual ionic content and achieve ASTM Type II quality.

Surface water sources, such as rivers or lagoons, require some pretreatment due to the presence of suspended solids and organic matter. Screening is required for single-pass cooling, while evaporative cooling additionally necessitates solids removal. Achieving PEM feedwater quality requires one RO pass, followed by EDI or ion exchange to meet ASTM Type II specifications.

BOX 2.5 *(CONTINUED)*

Groundwater typically shows more consistent quality than surface water but still requires treatment beyond cooling applications. Raw borehole water can be used directly for single-pass cooling, while evaporative cooling requires conventional pretreatment or membrane filtration. As with potable and surface water, one RO pass is required for boiler feedwater, followed by EDI or ion exchange to reach electrolysis-grade purity.

Seawater presents the most treatment-intensive pathway due to its high salinity. Screening is required prior to thermal applications, followed by membrane filtration for evaporative cooling. PEM feedwater quality is achieved through a first RO pass, followed by a second RO pass and final polishing via EDI or ion exchange.

Table B3.5.1 summarizes the raw water required to produce 1 kg of treated water for evaporative cooling and for ASTM Type II water quality used in PEM electrolyzers. The table shows how as more treatment is required to meet the water quality requirements, more recovery water is needed as well.

TABLE B2.5.1
Feed water required per unit of treated water by water source (kg/kg)

WATER SORCE	COOLING WATER (EVAPORATIVE COOLING)	AST TYPE I (ELECTROLYZER FEED)
Potable water	1.00	1.67
Surface water	1.06	1.68
Ground water	1.05	1.67
Seawater	1.06	3.27

Source: Based on CS-N0W (2024).

Estimated water consumption for ALK and PEM

Total raw water needs are estimated to amount between 50 to 67 l/kgH2 for ALK and 58 to 74 l/kgH2 for PEM, if once-through cooling is applied (CS-N0W 2024). Around 50–80 percent of the raw water needs are for cooling. Other cooling technologies can reduce or eliminate this water use.

As most large-scale projects under development today are close to the coast with seawater access, water is by project developers not seen as a key consideration. In fact, project designs may consider co-benefits for local communities, like project developers that are offering free drinking water supply to local populations. However proper water quality control is important to ensure smooth long-term operation of the electrolyzers.

Conclusion

The OPEX of a renewable hydrogen production facility is a critical determinant of its long-term economic performance. Electricity costs dominate the operating budget, reaching nearly $100 million per year under the assumed conditions of $50/MWh power price, 90 percent CF, and an energy consumption rate of 52 kWh/kgH2 produced (Table 2.3). Non-energy OPEX represents only about 3 percent of total CAPEX and is evenly distributed between fixed and variable components.

TABLE 2.3

Illustrative breakdown of annual operational expenditure for a $500 million electrolysis plant

TYPE OF EXPENSE	ANNUAL COST ($, MILLIONS)	PERCENTAGE OF TOTAL CAPITAL EXPENDITURE	COMMENT
Fixed	7.5	1.5	
Labor	2.5	0.5	Lean, automated team
Maintenance contracts	3.5	0.7	About 1.5% of equipment costs
Insurance and taxes	1.5	0.3	
Variable non-energy (annualized)	7.5	1.5	
Including: Stack replacement	6.0	1.2	$30 million every five years
Including: Consumables and water	1.5	0.3	Technology dependent
Total nonenergy operational expenditure (fixed + variable)	15.0	3.0	
Electricity operational expenditure	About 100.0	About 20.0	@ $50/MWh, 90% capacity factor, 52 kWh/kg

Source: World Bank staff, based on NREL H2A and IEA benchmarking data.

Over a 25-year project lifespan, cumulative OPEX is estimated to be five times greater than the initial CAPEX, highlighting the disproportionate impact of energy costs on overall economics. This finding reinforces the importance of optimizing energy efficiency, securing low-cost renewable power, and implementing strategies to mitigate degradation and consumable expenses to ensure the financial viability of large-scale renewable hydrogen projects.

The Levelized Cost of Hydrogen

The LCOH is a key metric for assessing the economic viability of hydrogen production, particularly for renewable pathways. It combines CAPEX and OPEX into a standardized measure, enabling cost comparisons across technologies. The LCOH is calculated by annualizing CAPEX—accounting for depreciation, financing costs, and project lifespan through a capital recovery factor—and then adding average annual OPEX. The sum of these annualized costs is divided by the annual hydrogen output, resulting in the LCOH expressed in dollars per kilogram of hydrogen.

The LCOH is an important economic indicator when comparing hydrogen production through different routes, which are broadly classified into gray, blue, and green categories based on feed-stock and emissions:

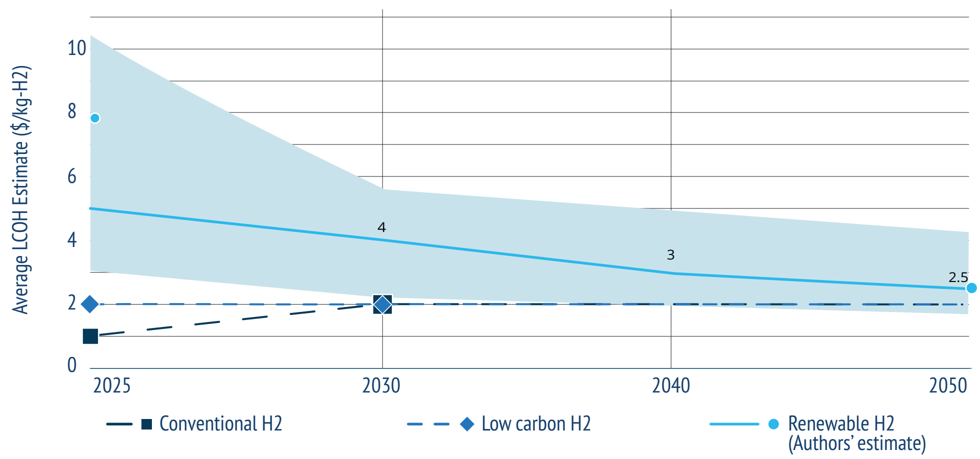
- Gray hydrogen, produced via steam methane reforming of natural gas, has historically dominated because of abundant and inexpensive natural gas.
- Blue hydrogen, often referred to as low-carbon hydrogen, builds on gray hydrogen, by incorporating carbon capture, utilization, and storage. Both gray and blue hydrogen face challenges such as methane leakage (which varies by upstream supply chain) and regional cost disparities, particularly in markets dependent on imported natural gas.
- Green hydrogen, produced via electrolysis powered by renewable energy, is more expensive than gray and blue hydrogen. The differential is gradually narrowing, however, as technological innovations and improvements in both CAPEX and OPEX drive greater efficiency and scalability. Despite these advances, green hydrogen remains in the early stages of commercialization, progressing from kilowatt-scale projects only a few years ago toward multi-gigawatt installations. Its adoption will require time, sustained innovation, and significant investment.

The Levelized Cost of Gray, Blue, and Green Hydrogen

Figure 2.8 illustrates the projected LCOH for three production pathways—conventional (gray), low-carbon (blue), and renewable (green)—between 2025 and 2050. Conventional hydrogen maintains the lowest and most stable profile (\$1.5–\$2.0/kgH2) throughout the forecast horizon. Low-carbon hydrogen starts slightly above conventional levels in 2025 but converges by 2030 and stabilizes thereafter, suggesting that incremental decarbonization measures impose only modest cost premiums once technologies mature.

FIGURE 2.8

Projected costs of gray, blue, and green hydrogen, 2025–50



Source: World Bank 2024.

Note: Figure aggregates cost estimates across various project types and scales from multiple studies, with gray and blue hydrogen reflecting optimal production locations. It assumes a carbon price of \$100/ton implemented from 2030 onward, adding around \$1/kgH2 to conventional hydrogen costs. Negative externalities associated with methane emissions are excluded. The shaded band around the renewable hydrogen trajectory indicates uncertainty, driven by variables such as renewable electricity prices, electrolyzer efficiency improvements, and financing conditions. H2 = hydrogen; kg = kilogram; LCOH = levelized cost of hydrogen.

Renewable hydrogen begins at a significantly higher cost—around $5/kgH2 in 2025—reflecting the current capital intensity of electrolyzer systems and renewable power integration. Its cost declines sharply, reaching $4/kg by 2030, $3/kg by 2040, and around $2.5/kg by 2050. This downward trend underscores the strong potential for renewable hydrogen to achieve cost parity with low-carbon alternatives by midcentury, contingent on continued technological innovation, economies of scale, and supportive policy frameworks.

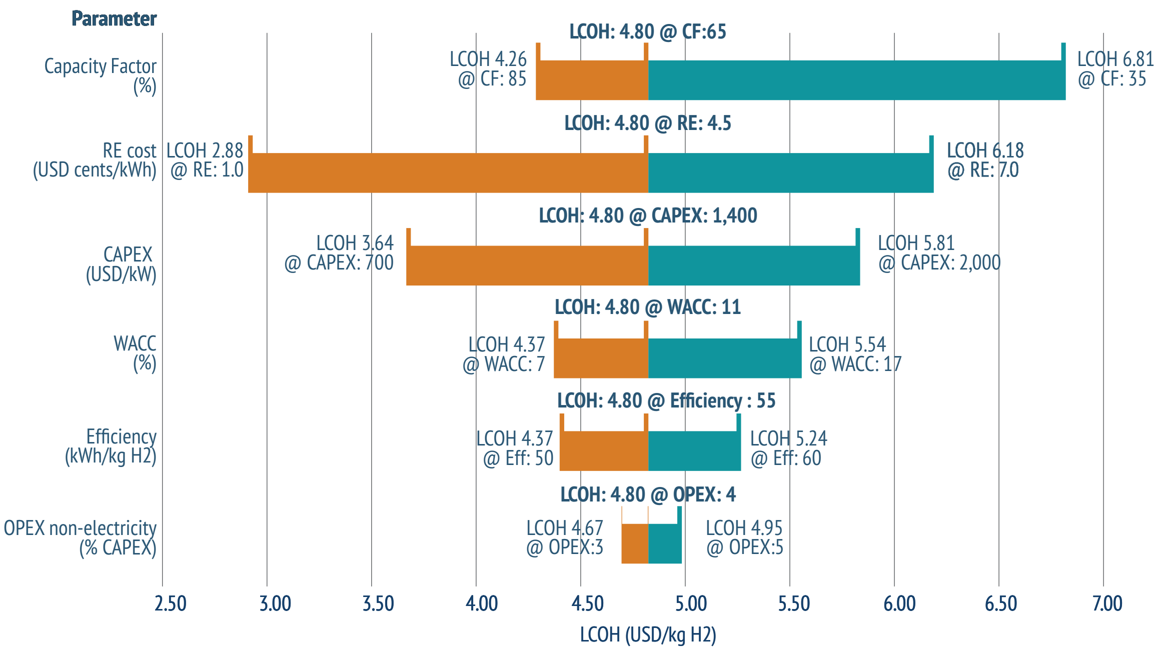
The analysis indicates that although conventional hydrogen remains cost competitive in the near term, its carbon intensity limits long-term viability under decarbonization mandates. Renewable hydrogen exhibits the steepest reduction trajectory, positioning it as a critical pathway for achieving deep emission reductions over time.

Estimating the Levelized Cost of Hydrogen

Significant uncertainty surrounds the data required to estimate the LCOH with confidence. A sensitivity analysis examines how variations in key assumptions or input variables affect these projections (Figure 2.9). The analysis reflects global uncertainty ranges that can help stakeholders understand which variables have the greatest effects on project outcomes and therefore where to focus efforts to strengthen projects' viability. The results show that the CF and the renewable electricity cost exert the greatest influence on the LCOH, followed by CAPEX. The WACC and electrolyzer efficiency have moderate impacts. Nonelectricity OPEX plays a comparatively minor role.

FIGURE 2.9

Sensitivity analysis of the levelized cost of hydrogen



Source: World Bank staff analysis.
Note: CAPEX = capital expenditure; CF = capacity factor; H2 = hydrogen; kg = kilogram; kWh = kilowatt-hour; LCOH = levelized cost of hydrogen; OPEX = operational expenditure; RE = renewable energy; USD = US dollar; WACC = weighted average cost of capital.

To achieve competitive costs, developers should focus to the extent possible on maximizing electrolyzer utilization and securing low-cost renewable electricity, both of which depend on resource quality and availability. Reducing CAPEX through optimized design, economies of scale, and supply chain efficiencies as well as lowering financing costs are also critical. Enhancing electrolyzer efficiency and operational flexibility to integrate with variable renewable energy (VRE) sources can further improve economics. Improvements across these parameters could enable LCOH reductions toward $2/kgH2 under favorable conditions.

The analysis highlights the importance of narrowing data ranges and uncertainty for all key parameters as the electrolyzer market matures. Greater transparency and more reliable data will enhance investor confidence and support more informed decision-making across the sector. Given the variability introduced by electrolyzer specifications and location-specific inputs, any attempt to define a universal LCOH benchmark would risk misrepresenting actual project economics. Instead, a Monte Carlo analysis provides some insights regarding ranges but is also limited by the underlying data quality (Box 2.6).

BOX 2.6

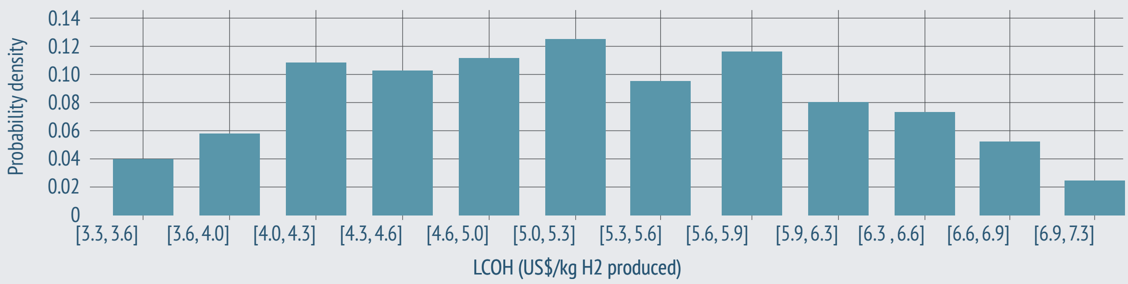
PROBABILISTIC ANALYSIS OF HYDROGEN PRODUCTION COSTS

A Monte Carlo simulation was conducted to quantify the impact of uncertainty in key financial and operational parameters on the levelized cost of hydrogen (LCOH) for a 20 MW hydrogen production facility employing alkaline technology. The parameters considered included the electricity price, total capital expenditure, the cost of debt, and the cost of equity, all of which affect project economics.

To capture the variability in plant utilization, the utilization rate was modeled as a linear function of electricity cost, reflecting the operational strategy of reducing production during periods of high electricity prices. For each simulation iteration, the LCOH was calculated using the financial structure and assumptions derived from a representative project framework, ensuring consistency with industry practice.

A large number of iterations was run to generate a probabilistic distribution of LCOH outcomes, providing insight into the range and likelihood of potential cost scenarios under varying market and financing conditions. This distribution illustrates the frequency of LCOH values across the simulated cases (Figure B2.6.1). The approach enables stakeholders to assess risk exposure, identify cost drivers, and support informed decision-making for early-stage project development.

Figure B2.6.1 • Monte Carlo analysis of levelized cost of hydrogen



Source: World Bank staff analysis

Note: H2 = hydrogen; kg = kilogram; LCOH = levelized cost of hydrogen.

Under current market and financing conditions, the estimated average cost of producing green hydrogen is around $5.20/kg. This baseline calculation assumes an electricity price of $0.048/kWh, a plant utilization rate of 69 percent, a cost of debt of 10.7 percent, and an equity return requirement of 17.4 percent, reflecting typical parameters observed in emerging markets and developing countries.

BOX 2.6 *(CONTINUED)*

The results indicate that production costs follow a normal distribution, centered around $5.20/kg, with a standard deviation of 0.94. This probabilistic spread underscores the sensitivity of hydrogen economics to variations in electricity pricing, financing terms, and operational factors. Based on this distribution, 90 percent of projects in emerging markets and developing countries are expected to fall within a cost range of $3.60–$6.70 /kg under prevailing conditions.

Only a small fraction of projects (fewer than 5 percent) are projected to achieve costs below $3.60/kg. These outliers represent scenarios with highly favorable electricity tariffs and financing structures, making them the most likely candidates for commercial viability without subsidies or policy support. For the majority of projects, achieving competitive cost levels will require targeted interventions, such as concessional financing, renewable energy integration, and technology improvements, to reduce capital intensity and enhance efficiency.

Developers can incorporate key factors while designing projects. They include the technology choice and installation approach, which determines CAPEX; stack lifespan and replacement costs, which affect long-term maintenance; and the technology readiness level, which affects risk perception and financing costs. Operational flexibility is also essential for integrating with VRE sources.

Estimates indicate that the LCOH can range from around $2/kg under optimal conditions to $10–$15/kg in less favorable scenarios. A typical CAPEX of $1,500/kW, combined with a 50 percent CF and a 15 percent annuity results in a capital cost contribution of around $2.5/kgH2. Increasing the CF enhances annual hydrogen output, reducing the per-unit capital cost. Lowering the financing cost decreases the annuity rate, further improving cost efficiency. For instance, a 90 percent CF—achievable in hydropower-based systems—can nearly halve the CAPEX contribution to the LCOH.

OPEX plays a critical role in shaping the long-term economics of electrolyzer systems. Energy costs dominate OPEX, but non-energy components, such as labor, maintenance, consumables, and insurance, also contribute. Understanding benchmark ranges for these expenses is essential for evaluating system performance, comparing technology options, and planning for financially sustainable projects. For mature, large-scale electrolysis facilities (larger than 50 MW), annual nonenergy OPEX typically ranges from 2 percent to 5 percent of total installed CAPEX, underscoring the importance of both technical and operational optimization in hydrogen cost modelling.

The lower range (2–3 percent) typically applies to large-scale, mature ALK electrolysis plants (this estimate assumes that stack replacement costs are annualized and included in the overall OPEX). These facilities benefit from high operational availability, advanced automation, favorable labor costs, and a well-established maintenance and supply chain.

The upper range (3.5–5.0 percent) is more representative of PEM systems, first-of-a-kind projects, and facilities located in high-cost regions. It also applies to operations with complex requirements, such as frequent cycling, which can increase wear and maintenance needs. This higher range also accounts for elevated insurance premiums, property taxes, and other region-specific overheads that raise operating costs.

The Levelized Cost of Hydrogen in Brazil, Namibia, and India

This section explores how key cost components influence hydrogen production costs under different regional conditions. The analysis compares the LCOH in Brazil, Namibia, and India solely for illustrative purposes—to examine how LCOH changes when CAPEX is kept constant, but variations are introduced in renewable energy costs, capacity utilization, and the WACC. These comparisons are not intended as global benchmarks; rather, they serve to demonstrate the sensitivity of LCOH to renewable resource quality and financing assumptions under uniform CAPEX conditions.

The assessment covers three renewable hydrogen projects located in Ceará (Brazil), Lüderitz (Namibia), and Gujarat (India), each employing distinct renewable configurations and financial parameters. All sites model three electrolyzer technologies: Asian-made alkaline, European-made alkaline, and European-made PEM. Their cost structures differ significantly, because of differences in CUFs, electricity prices, and the WACC.

All three sites are modelled with a solar-wind hybrid configuration, with the CUF varying according to resource quality. Brazil's Ceará site is estimated to have a CUF of 70 percent, an electricity price of \$0.045/kWh, and a WACC of 10.3 percent. Namibia's Lüderitz site is projected to achieve a CUF of 65 percent, an electricity price of \$0.04/kWh, and a WACC of 12.8 percent, indicating greater financing risk. India's Gujarat site is assumed to have the lowest CUF, at 55 percent, with an electricity price of \$0.04/kWh and a WACC of 9.7 percent.

Differences in resource quality and financing conditions have a pronounced impact on LCOH utcomes (Figure 2.10). Brazil's high CUF enables annual hydrogen production of 10.99–11.45 kilotons per annum (ktpa), enhancing capital recovery and lowering per-unit costs despite slightly higher electricity prices. Namibia benefits from strong wind resources, achieving 10.17–10.63 ktpa, but its elevated WACC significantly increases financing costs, resulting in a higher LCOH than Brazil. India faces the greatest challenge, with a lower CUF and moderate electricity prices limiting output to 8.54–8.99 ktpa and driving up costs, even though its relatively low WACC partially offsets financing burdens.

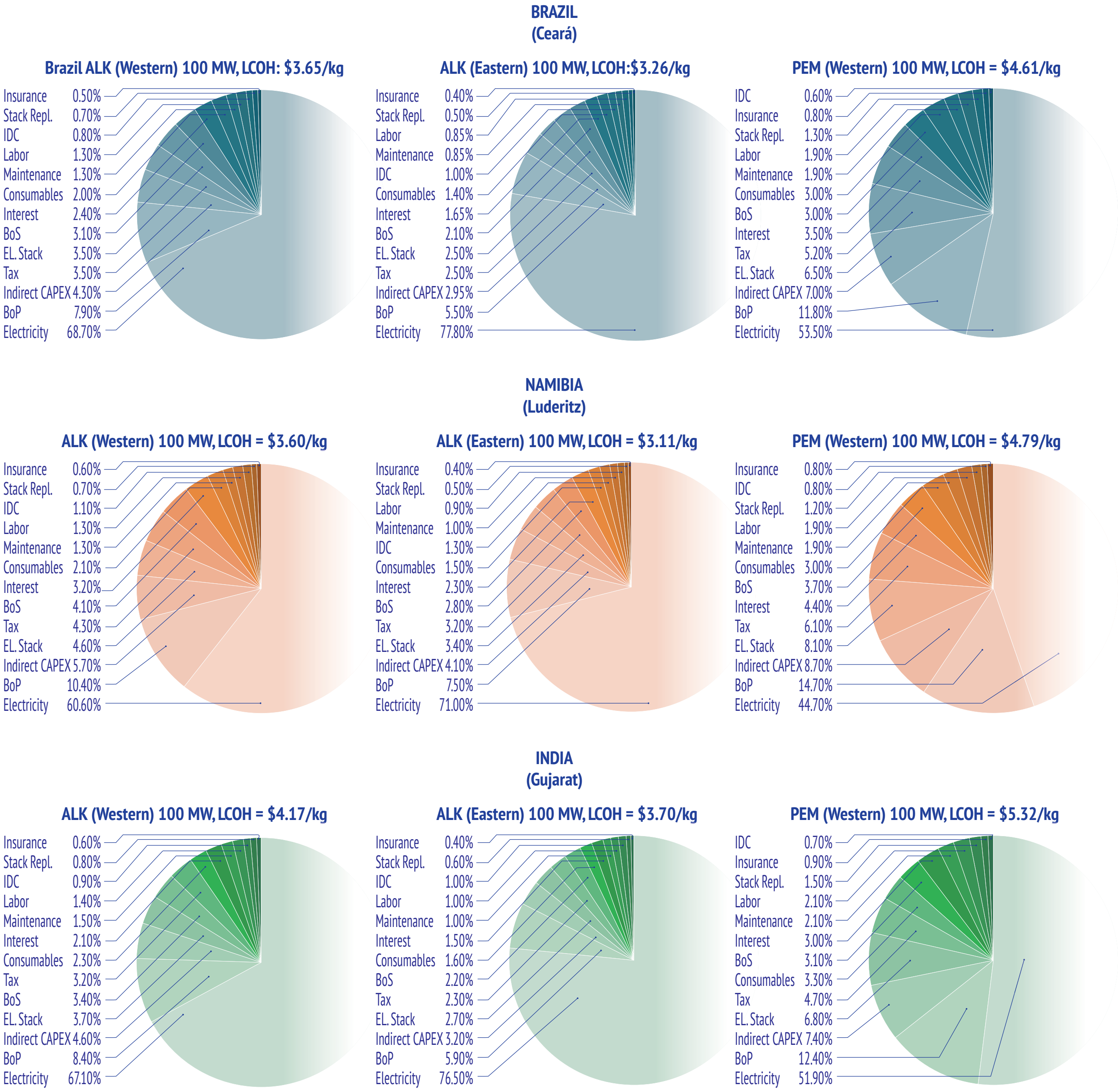
The analysis reveals consistent cost composition patterns while highlighting regional variations shaped by renewable resource quality, electricity pricing, and financing terms. The findings underscore the critical interplay between CAPEX, OPEX, and financing in determining hydrogen project economics.

OPEX remains the dominant cost component for all configurations, primarily through electricity costs, but its relative share declines as CAPEX rises. In Brazil, where CUF is highest (70 percent) and electricity costs are moderate (\$0.045/kWh), the Asian-made ALK electrolyzer achieves an LCOH of \$3.26/kg, with electricity contributing nearly 78 percent of total cost. For the European-made ALK system (\$3.65/kg), electricity falls to 69 percent; the PEM system (\$4.61/kg) sees electricity drop to 53 percent as CAPEX becomes more significant. A similar trend is observed in Namibia, where strong wind resources (CUF 65 percent) and slightly lower electricity prices (\$0.04/kWh) reduce OPEX shares, to 71 percent for an Asian ALK (\$3.11/kg), 60.6 percent for European or North American ALK (\$3.60/kg), and 44.7 percent for PEM (\$4.79/kg). India, with the lowest CUF (55 percent) and comparable electricity rates (\$0.04/kWh), shows the highest OPEX dominance for Asian ALK, at 76.5 percent (\$3.70/kg). It drops to 67.1 percent for European or North American ALK (\$4.17/kg) and 51.9 percent for PEM (\$5.32/kg). These Figures confirm that resource quality and utilization factors strongly influence the weight of electricity in the LCOH.

CAPEX contributions escalate sharply with technological complexity, particularly for PEM systems. In Brazil, CAPEX accounts for less than 10 percent for Asian ALK, around 15 percent for European or North American ALK, and more than 20 percent for PEM, driven by BoP and stack costs. Namibia exhibits an even steeper gradient: 13.7 percent for Asian ALK, 19.8 percent for European or North American ALK, and nearly 29 percent for PEM, reflecting the compounding effect of higher financing risk and capital recovery requirements.
India shows a similar pattern, though absolute shares are slightly lower thanks to a favorable

FIGURE 2.10

Estimated levelized cost of hydrogen in Brazil, Namibia, and India under varying conditions



Source: World Bank staff analysis.

Note: "Eastern" manufacturers are Asian, and mostly Chinese; "Western" manufacturers are located in Europe and North America. ALK = alkaline; BoP = balance of plant; BoS = balance of stack; CAPEX = capital expenditure; EL = electrolyzer; IDC = interest during construction; kg = kilogram; LCOH = levelized cost of hydrogen; MW = megawatt; PEM = proton exchange membrane.

WACC: 10.8 percent for Asian ALK, 16.3 percent for European or North American ALK, and 22.3 percent for PEM. Stack replacement remains marginal across all cases but adds incremental pressure on PEM economics.

Financing costs scale with both WACC and CAPEX intensity, amplifying differences between sites and technologies. Brazil's moderate WACC (10.3 percent) keeps financing contributions at 5 percent for Asian ALK, 6–7 percent for European or North American ALK, and nearly 10 percent for PEM. Namibia's higher WACC (12.8 percent) pushes these shares to 6.8 percent, 8.6 percent, and 11.3 percent, respectively, with tax alone exceeding 6 percent for PEM. India benefits from the lowest WACC (9.7 percent), limiting financing costs to 4.8 percent for Asian ALK, 6.2 percent for European or North American ALK, and 8.4 percent for PEM. These trends underscore that financing conditions are as critical as technology choice in determining LCOH competitiveness, particularly for capital-intensive PEM systems.

The special case of Ceará, in Northeast Brazil, was evaluated because of its exceptional renewable energy profile. As of February 2024, over 90 percent of its grid electricity came from hydro, wind, and solar, consistently meeting local demand and enabling clean energy exports. Ceará has thus become a strategic hub for green hydrogen production. For this scenario, a CUF of 90 percent was applied, with other assumptions such as WACC and electricity costs unchanged. Increasing the CUF from 70 percent to 90 percent delivers a substantial performance gain: Annual hydrogen output rises from 10.99 ktpa to 14.26 ktpa—about a 30 percent increase—and the LCOH falls from $3.26/kg to $3.11/kg, a 4.6 percent reduction. This improvement is driven by better asset utilization and the dilution of fixed costs, which significantly reduces the proportional impact of capital-related components and nonenergy OPEX. Electricity remains the dominant cost driver (81.9 percent for a CUF of 90 percent versus 77.8 percent for a CUF of 70 percent), reflecting higher consumption. Its share underscores the sensitivity of the LCOH to power pricing. Operating at a higher CUF enhances production efficiency, optimizes capital amortization, and reinforces economies of scale, making high utilization a critical lever for cost competitiveness in green hydrogen projects.

Electricity remains the largest cost driver across all sites and technologies, but its dominance diminishes as CAPEX and financing escalate, especially for PEM electrolyzers. Regional factors such as the CUF and the WACC significantly affect cost composition: Brazil leverages high utilization to offset moderate electricity rates, Namibia's strong wind resource is partially undermined by higher financing risk, and India faces challenges from lower CUF despite favorable financing. Achieving a lower LCOH requires a dual strategy: reducing electricity costs through resource optimization and addressing CAPEX and financing constraints, especially for advanced electrolyzer technologies.

For project developers, the priority should be securing low-cost renewable electricity, as electricity remains the largest driver of the LCOH. They can do so through long-term PPAs, hybrid solar-wind configurations to maximize the CUF, and co-location strategies to reduce transmission costs. On the CAPEX side, developers should leverage local supply chains, pursue standardized designs, and aim for large-scale deployments to capture economies of scale. Financing strategies are critical: Developers should actively seek risk mitigation instruments, such as government-backed guarantees, concessional loans, and tax benefits, to lower WACC and improve project bankability. Technology choices should balance cost and flexibility. Although ALK systems offer lower up-front costs, PEM systems provide operational adaptability for VRE integration. Developers should also adopt transparent cost reporting and benchmarking practices, using real-world data to strengthen investor confidence and support financing negotiations.

Costs of Electrolyzer Systems, by Region of Manufacture

The accelerated expansion of the global renewable hydrogen sector has triggered intense competition in electrolyzer manufacturing, creating a race for technological and cost leadership. This dynamic has resulted in a bifurcated market structure consisting of established European and North American OEMs with mature supply chains and proven technologies on one side and rapidly scaling Asian manufacturers—predominantly Chinese—leveraging economies of scale and aggressive cost optimization on the other.

China has the largest deployment base for electrolysis systems and is exerting downward pressure on global electrolyzer costs, reshaping competitive benchmarks (IEA 2025). Also, India is emerging as a significant manufacturing hub, supported by strong policy signals (Box 2.7). This rapid scale-up, combined with global cost compression trends—such as Sinopec's Ordos project achieving record-low electrolyzer prices—underscores a future in which manufacturing scale, technology innovation, and regional industrial strategies will define competitiveness in the hydrogen economy.

Price Considerations

Quantitative insights from project tenders, vendor quotations, and market intelligence consistently highlight a significant cost differential between European or North American and Asian systems, especially in ALK electrolysis. However, meaningful cost comparisons must be normalized across key parameters: technology type, system capacity, and scope of supply (e.g., BoP, integration level), to ensure an apples-to-apples evaluation.

The cost of European and Asian electrolyzers are similar at the stack level; differences are in the BoS and BoP. For large-scale (more than 50 MW) ALK systems, the difference between the CAPEX of European and Asian manufacturers is large. Meanwhile, the technologies are broadly comparable in terms of cost and performance. The premium associated with European and North American systems typically stems largely from the BoS and BoP components, such as electrolyte tanks, gas-electrolyte separators, and ancillary piping and connections. These components are technically straightforward but labor intensive to fabricate and assemble. This premium could be significantly reduced if BoS components were manufactured in the country of deployment, using blueprints and technical specifications provided by the OEM. Such localization strategies offer a viable pathway to narrowing the cost gap while maintaining system integrity and performance.

BOX 2.7

INDIA'S EMERGENCE AS AN ELECTROLYZER MANUFACTURING HUB

India is rapidly emerging as a competitive hub for electrolyzer manufacturing, driven by strong market signals and strategic incentives aimed at scaling domestic production. The country's manufacturing ecosystem is being shaped by the performance-linked incentive scheme under the Strategic Interventions for Green Hydrogen Transition program, which allocates $2.12 billion to accelerating capacity build-out and improving cost competitiveness.

India has an operational manufacturing capacity of nearly 500 MW, led by companies such as Ohmium, Advait, and L&T. In addition, 3,000 MW of annual electrolyzer manufacturing capacity has been awarded under the Strategic Interventions for Green Hydrogen Transition scheme across two tranches, positioning India as one of the world's fastest-growing electrolyzer markets. The first tranche, released between June 2023 and January 2024, allocated 1,500 MW per year to eight major players, including Reliance, L&T, Jindal, Adani, and Greenko. The second tranche, released between March 2024 and January 2025, added another 1,500 MW per year across 13 companies. Facilities under the first tranche are expected to be commissioned by mid-2026; plants under the second tranche will come online by mid-2027.

Electrolyzers manufactured under the performance-linked incentive scheme must meet performance benchmarks, including an operational life of at least 60,000 hours, efficiency of at least 80 percent, and energy consumption that does not exceed 56 kWh/kgH2. In addition, local value addition requirements will progressively increase over five years—from 40 percent to 80 percent for alkaline technology and from 30 percent to 70 percent for proton exchange membrane, solid oxide electrolysis cell, and anion exchange membrane technologies. Incentives will be disbursed quarterly over five years following commissioning, with strict deadlines set at 30 months from the respective letters of award, ensuring timely execution and alignment with India's target of establishing a robust electrolyzer manufacturing ecosystem by 2030.

Source: MNRE 2025; SECI 2023, 2024.

CAPEX is much higher in PEM systems than in ALK systems. The cost differential between Asian and European manufacturers is smaller, however (Figure 2.11, panel b). Asian PEM systems are currently priced at $700–$1,000/kW; PEM systems from Europe and North America, meanwhile, cost $1,000–$1,600/kW. This narrower gap reflects the larger material cost share in PEM technology, particularly for globally traded commodities like iridium-based catalysts and PEM, which limit regional cost advantages. PEM manufacturing in Asia is at an earlier stage of industrial scaling than ALK systems. Chinese CAPEX is often lower—sometimes by a factor of two to four—but these figures frequently exclude critical elements such as BoP, grid interconnection, and soft costs. Direct comparisons must be normalized across identical system definitions, including stack, BoP, interconnection, commissioning, and warranties.

Projections for 2030–50 suggest declining CAPEX across all locations, with potential convergence or persistent gaps depending on policy frameworks, trade dynamics, and supply chain resilience. For accurate capital planning, it is essential to obtain firm quotes from suppliers with harmonized scope to ensure a true apples-to-apples comparison.

Nonprice Considerations

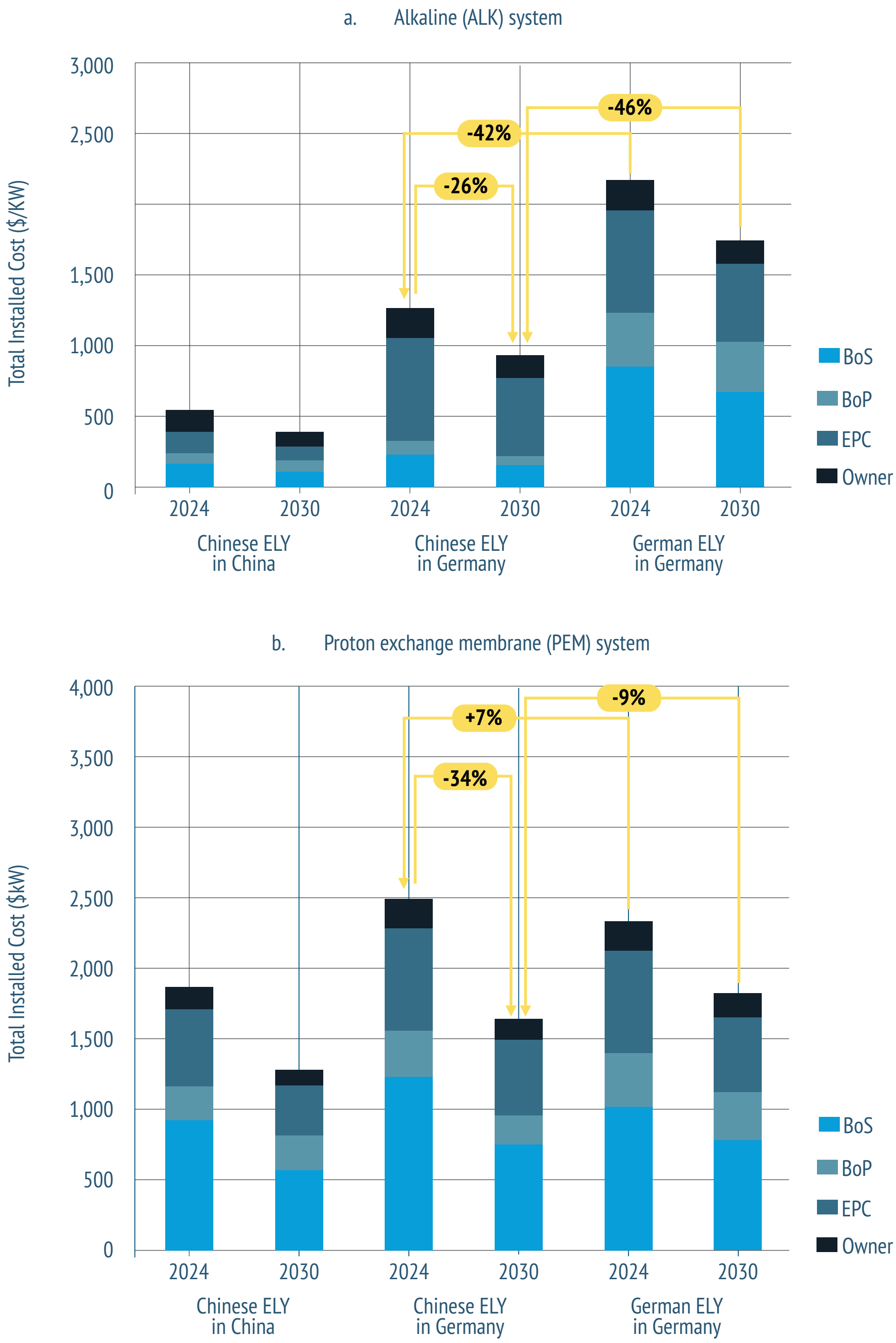
Nonprice factors increasingly shape the competitive landscape for clean hydrogen projects. Disparities between European and Chinese electrolyzer systems are not driven solely by technology maturity or performance but reflect a complex interplay of supply chain structure, industrial policy, compliance requirements, and strategic procurement frameworks. These considerations extend beyond equipment specifications to encompass sustainability, resilience, and regulatory alignment—elements that are now embedded in European public procurement policies. It should also be noted that supply chains are intertwined and the specifications Asian and European do not reflect this complexity.

Since 2024, the European Union (EU) has increasingly embedded nonprice criteria in hydrogen procurement to strengthen sustainability, resilience, and industrial competitiveness. Its Innovation Fund uses descriptive award criteria focused on replicability, efficiency gains, environmental impact, scalability, and technology transfer, although they are nonbinding. The European Hydrogen Bank has progressed from collecting quality data to enforcing origin-based restrictions, limiting electrolyzer stack components from China to 25 percent, a rule expected to remain in place. The Net Zero Industry Act formalizes sustainability benchmarks (such as recycling, energy efficiency, and life-cycle assessment) and resilience measures to reduce reliance on oversupplied third countries, with exemptions under the World Trade Organization Agreement on Government Procurement or where costs escalate. Complementary initiatives, such as the Clean Industrial Deal and the Industrial Decarbonization Accelerator Act, extend these principles to energy-intensive sectors, adding criteria on cleanness, circularity, and cybersecurity to promote innovation and fair competition.

Application of the criteria is progressing, albeit through different approaches. The European Global Gateway is exploring strategic procurement opportunities, even as it works to address financing complexities beyond fully European sources. Although nonprice criteria are currently not applied to imports of hydrogen derivatives, they are counted toward EU regulatory targets.

FIGURE 2.11

Total installed investment cost of a 20 MW electrolyzer, 2024 and 2030



Source: Wood Mackenzie 2024.

Note: BoP = balance of plant; BoS = balance of stack; ELY = electrolyzer system; EPC = engineering, procurement, and construction; kW = kilowatt.

Structural and Operational Drivers of Procurement Decisions

Beyond regulatory frameworks and policy-driven incentives, procurement choices in the clean hydrogen sector are shaped by a complex set of industry-level factors that directly affect project economics, technical feasibility, and long-term reliability. These differentiators encompass structural attributes (such as supply chain integration, manufacturing scale, and technology specialization) as well as operational considerations (including compliance readiness, certification standards, and life-cycle performance guarantees). Together, these elements define the competitive positioning of electrolyzer manufacturers and influence buyer preferences in markets where cost is only one dimension of value. Understanding these drivers is essential for stakeholders seeking to balance up-front capital efficiency with strategic objectives such as bankability, operational resilience, and alignment with sustainability benchmarks. Key drivers of China's success are discussed below.

Vertical integration and supply chain localization. Chinese manufacturers benefit from vertically integrated or domestically sourced supply chains for critical components such as bipolar plates, catalysts, membranes, current collectors, power electronics, and BoP assemblies. This proximity to upstream suppliers reduces logistics costs, import duties, lead times, and intermediary margins, resulting in lower input costs and streamlined procurement. In contrast, European and North American OEMs often rely on globally distributed suppliers, many of which are based in Asia, leading to higher shipping costs, customs overheads, trade exposure, and inventory holding costs. Compliance with local content mandates; certifications (e.g., CE and UL certifications); and regulatory standards in European and to a lesser degree North American markets add to cost burdens.

Government subsidies, incentives, and strategic industrial policy. China's electrolyzer industry benefits from an extensive suite of state-backed support mechanisms that significantly reduce capital costs and accelerate deployment. In addition to subsidies, tax incentives, and preferential access to land and utilities, Chinese firms frequently secure highly concessional loans, substantially lowering financing costs compared with global peers. This advantage is reinforced by the presence of public entities across the value chain—both upstream in electrolyzer manufacturing and downstream in green hydrogen production—creating an integrated ecosystem that ensures demand certainty, facilitates large-scale procurement, and enables coordinated infrastructure development. These features have helped manufacturers scale rapidly and offer highly competitive pricing while maintaining margins. The approach mirrors China's earlier industrial strategies in solar photovoltaic and battery manufacturing, resulting in over 60 percent of global electrolyzer production capacity and system costs as low as \$300–\$500/kW—roughly one-quarter of European or US prices. In contrast, European and North American governments primarily deploy demand-side incentives, such as the US Production Tax Credit, Department of Energy grants, and the EU Innovation Fund. Although these mechanisms reduce project risk and stimulate domestic demand, they often favor higher-cost local equipment.

BoP compatibility and integration. Chinese OEMs focus on pressurized ALK electrolyzers, leveraging standardized designs with compact BoP packages and limited EPC services. This focus yields cost-effective systems but reduces customization and integration. European manufacturers emphasize PEM and advanced ALK or SOEC technologies, offering comprehensive system integration—including transformers, rectifiers, cooling systems, gas purification, and handling—delivered as certified skids. These systems are designed to meet stringent standards such as ISO 22734, ATEX/IEC 60079, NFPA 2, and DNV-ST-J301. Chinese systems often require additional certification, documentation, and engineering to meet European and US market requirements, which can erode initial cost advantages.

Certification, compliance, and standards qualification. Projects in Europe and North America must comply with local electrical codes, hydrogen safety regulations, grid interconnection protocols, and environmental standards. Western OEMs typically hold the necessary certifications; Asian suppliers may require additional validation, third-party audits, or documentation, introducing cost and schedule risks. Financing institutions—including banks and export credit agencies—often prefer certified, proven technologies, which can tilt procurement decisions in favor of Western suppliers.

Manufacturing scale, learning rates, and production volume. Global electrolyzer manufacturing capacity reached around 60.9 GW a year in mid-2025, with China accounting for over 60 percent of this capacity. Demand remains modest, however, with only 2.15 GW in operation and 15.8 GW under construction. China's domestic project concentration allows higher factory throughput and better utilization, driving down unit costs (Box 2.8). European and North American production is fragmented and smaller in scale, spreading fixed costs over fewer megawatts. China's dominance is especially pronounced in ALK electrolyzers, with 11 of the 12 largest plants located there. Europe's focus on PEM and the United States' emphasis on SOEC contribute to higher costs, because those systems require complex designs and expensive materials.

Performance warranties and operational lifespan. Chinese OEMs often advertise extended warranties of 20–25 years, but they are not always backed by robust financial guarantees, raising concerns about long-term bankability. Their lower up-front costs have made them attractive in emerging markets such as Latin America and Africa, where procurement decisions prioritize capital efficiency. European OEMs typically offer warranties aligned with stack lifetimes (2–10 years). They are supported by stronger balance sheets and, in some cases, export credit agency backing. To enhance OPEX predictability and project bankability, European suppliers increasingly bundle long-term service agreements into their offerings.

BOX 2.8

WHY IS THE PRICE OF CHINESE ELECTROLYZERS SO LOW?

China plays a decisive role in shaping global electrolyzer markets, particularly for alkaline (ALK) technology, which currently leads in both global installed capacity and project pipeline. This dominance has raised concerns in other regions, especially regarding China's large manufacturing overcapacity and the very low costs of its ALK equipment compared with international competitors. China holds roughly 85 percent of global ALK electrolyzer manufacturing capacity. In early 2025, it was reported that ALK stack-plus-balance of plant prices in China fell to about $108/kW, about one-fourth to one-sixth of comparable offers in Europe (Collins 2025a). A Sinopec auction late 2025 awarded stack-only contracts at around $70/kW.

These market conditions have triggered fundamental questions from stakeholders about how Chinese firms are achieving such low prices, the role of government support, and the robustness of quality assurance frameworks. A seminar was organized in Inner Mongolia by China's Hydrogen Energy Industry Promotion Association on November 3, 2025, to address the Chinese government's directive to curb "involution-style" competition, marked by extreme price undercutting, overstated performance claims, and capacity additions far exceeding real demand for electrolyzers. Bringing together manufacturers, project owners, and media, the meeting aimed to strengthen self-regulation, restore fair competition, and build a sustainable industrial ecosystem.

The event concluded with the joint release of the "China Electrolyzer Industry Healthy Development Initiative," which outlines 10 commitments designed to stabilize both domestic and international electrolyzer markets (Collins 2025b):

- Avoiding exaggerated capacity or efficiency claims
- Avoiding pessimism due to cancelation of projects
- Ensuring that all performance metrics are supported by verifiable testing
- Ending below-cost price wars
- Increasing transparency through third-party data
- Prioritizing genuine technological innovation over indiscriminate capacity build-out
- Strengthening testing and certification standards
- Reducing reliance on subsidies
- Strengthening industry collaboration
- Promoting responsible international expansion that respects local laws, cultural norms, and intellectual property protections.

BOX 2.8 *(CONTINUED)*

If effectively implemented, these measures may influence global market dynamics. Moderation of China's rapid price declines could bring more stable capital expenditure expectations. Enhanced data transparency may improve clarity on efficiency and degradation rates—key bankability parameters discussed in this report. A sharper focus on compliance and reputation abroad may mitigate concerns related to warranties, certification compatibility, and execution quality.

Chinese electrolyzer manufacturers are also expanding internationally to comply with local content requirements, especially in Europe, and to secure long-term market growth. Companies are combining direct investment, strategic partnerships, and accelerated product scaling to establish a competitive presence in new regions. Firms such as Envision, Trina, Hygreen, and Guofu HEE have announced manufacturing bases or project investments in Europe, particularly in Spain and Germany (Hydrogen Insights 2025c). Many of these initiatives involve equity partnerships or licensing agreements with European or US companies, such as Peric with Metacon and Sungrow with BrightHy Solutions, facilitating compliance with European standards and lowering market entry barriers.

Chinese original equipment manufacturers are also broadening their presence in Latin America, the Middle East, and Africa. China's Hygreen and Guofu are building electrolyzer factories in Chile. Envision has signed a strategic partnership in Brazil for a 0.5 GW green hydrogen project in Brazil. Sungrow Hydrogen has partnered with Seven Seas Petroleum in Oman to advance the country's objective to produce 1 million tons a year of renewable hydrogen.

III. Pathways to Reducing Costs

Key Points

- With roughly two-thirds of the levelized cost of hydrogen (LCOH) driven by electricity, the dominant strategies for near-term cost reduction are strategies that lower the cost of electricity. They include optimizing location selection and the choice of power mix. Advances in battery technologies are paving the way for innovative system configurations that leverage low-cost solar photovoltaic (PV) power as a primary energy source.
- Although the electrolyzer stack accounts for less than half of total system capital expenditure (CAPEX), it remains the focus of manufacturing innovation and research and development (R&D) to prompt cost reduction. Innovations are targeting reductions in the use of precious metals within proton exchange membrane (PEM) electrolyzers. Next-generation electrolyzer designs are aiming to enhance electrical efficiency by up to 20 percent.
- Cutting-edge manufacturing processes are being implemented globally to drive down stack costs. Advances in manufacturing automation and design optimization are expected to streamline production processes and enhance cost efficiency.
- Balance of stack (BoS) and balance of plant (BoP) components offer the greatest potential for cost savings. Realizable savings are predominantly tied to economies of scale, augmented by design standardization, modular skids, and supply chain consolidation.
- In emerging markets and developing countries (EMDCs), efforts to lower total project costs have concentrated on reducing engineering, procurement, and construction (EPC) expenses, as well as lowering the costs associated with civil works and building infrastructure.
- Artificial intelligence (AI)-driven automation, digital twin technologies, and predictive maintenance systems hold the potential of reducing both capital and operational expenditure in electrolyzer projects. These technologies can accelerate commissioning, extend the operational lifespan of electrolyzer stacks, and improve capacity factors, thereby lowering the LCOH.
- Operating track records, bankable performance guarantees, and the emergence of standardized plug-and-play electrolyzers can lower risks premiums, decreasing financing costs

and improving project bankability. Operating track records, bankable performance guarantees, and the emergence of standardized plug-and-play electrolyzers can lower risks premiums, decreasing financing costs and improving project bankability.

This chapter analyzes six pathways that can help lower the cost of hydrogen projects:

- Securing low-cost electricity.
- Reducing CAPEX by refining the scope of EPC and optimizing BoP and BoS.
- Accelerating stack innovation, through advanced manufacturing, novel materials, and improved efficiency.
- Digitalizing the project life cycle.
- Reducing financing costs by deploying technology risk mitigation instruments such as warranties, performance guarantees, insurance, and blended finance.
- Creating common user infrastructure.

Securing Low-cost Electricity

Electricity accounts for about two-thirds of the LCOH, making power cost reduction the most critical lever for near-term cost improvements. Renewable electricity prices vary significantly in EMDCs, because of differences in resource quality, transmission costs, market conditions, and regulatory frameworks. Delivered prices for utility-scale renewable power can range from as low as $0.01/kilowatt-hour (kWh) in highly favorable locations to more than $0.10/kWh in less optimal areas. This variability, combined with differences in resource profiles, directly affects the choice of electrolyzer technology, the configuration of the plant, and ultimately the LCOH. To manage the potential impact of high electricity costs, developers can adopt strategies such as optimizing site selection to access superior renewable resources, minimizing transmission expenses, and structuring power procurement to capitalize on market dynamics—by securing low-cost nonpeak power or competitively priced open-access electricity, for example.

Developers are also deploying innovative system designs to leverage low-cost PV power as the primary energy source, supported by storage to smooth variability. With battery system costs having declined to $65/kWh (Renew Economy 2025), several-hour storage configurations in high-irradiance locations are now technically and economically plausible. In solar-resource-rich desert locations (such as Namibia), for example, several-hour battery storage is being paired with alkaline (ALK) electrolyzers to substantially smooth variability, improve stack utilization, and enable broader operating windows. Direct current (DC) coupling is also being explored to avoid alternating current (AC)-DC conversion losses and reduce capital cost, particularly where DC sources (e.g., solar PV) are the dominant source of energy supply. The use of batteries and advanced power electronics has design implications: By reducing variability, plants may optimize stack types and power conditioning that favor steady-state operation and lower BoP complexity.

Regulatory frameworks and sustainability standards further shape the feasible power supply strategies and flexibility requirements. India allows the banking of renewable power, so that the producer can receive 24/7 grid supply while contracting solar-only power purchase agreements. In contrast, forthcoming rules in the European Union (EU) require hourly matching of renewable generation and consumption (EU 2024). Such differences can tilt the choice toward more flexible PEM systems in the European Union, whereas ALK may be favored where firmed supply exists or banking is permitted (Box 3.1).

BOX 3.1

HOW DO TWO SETS OF EU RULES AFFECT RENEWABLE HYDROGEN ECONOMICS AND SYSTEM DESIGN?

The European Union's Renewable Energy Directive (RED II and RED III) and associated rules for Renewable Fuels of Non-Biological Origin impose stringent sustainability criteria on green hydrogen production (European Commission 2023). Central to these requirements are three principles— additionality, temporal correlation, and geographic correlation—each of which significantly influences project design, operational flexibility, and cost competitiveness.

The principle of **additionality** requires that renewable electricity used for hydrogen production originate from newly installed renewable capacity rather than existing assets. This provision ensures that electrolyzer operation does not divert power from the grid or undermine broader decarbonization objectives. To comply, developers must either co-locate electrolyzers with dedicated renewable generation or secure long-term power purchase agreements linked to newly commissioned assets. Although this approach strengthens the environmental integrity of renewable hydrogen, it introduces higher up-front capital requirements and financing complexity, as projects often need to bundle electrolyzer investments with renewable generation infrastructure. Consequently, additionality can increase the levelized cost of hydrogen (LCOH) compared with scenarios in which unrestricted grid electricity is used, particularly in early-stage markets with limited renewable penetration. By enforcing additionality, the European Union ensures that hydrogen supplied to industry is genuinely renewable and prevents the market from being flooded with lower-cost, high-carbon hydrogen alternatives, thereby safeguarding climate objectives and maintaining credibility in green hydrogen certification.

Temporal correlation requires that hydrogen production align with renewable electricity generation within defined time windows—currently hourly matching under RED III from 2030 onward. This constraint limits electrolyzer utilization during periods of low renewable output, reducing capacity factors and increasing the effective cost per kilogram of hydrogen. To mitigate these impacts, developers may deploy battery storage or oversize renewable capacity, both of which add to project capital expenditure.

BOX 3.1 *(CONTINUED)*

Alternatively, they can opt for proton exchange membrane (PEM) electrolyzers, which have superior dynamic response and ability to ramp quickly and are better suited for intermittent operation than alkaline systems, which operate better with steady-state loads. Compliance with temporal correlation tends to favor PEM technology, despite its higher stack cost, as it minimizes curtailment and optimizes renewable integration.

Geographic correlation stipulates that renewable electricity must be sourced from the same bidding zone or interconnected region as the electrolyzer facility. This rule limits the ability to procure low-cost renewable power from distant regions and may constrain siting flexibility. Projects in areas with high-quality renewable resource (e.g., solar-resource-rich southern Europe or wind-rich northern Europe) will benefit from lower generation costs; projects in less favorable zones face higher LCOH, from higher power purchase agreement prices and grid charges. Geographic restrictions also affect infrastructure planning, reinforcing the need for hydrogen production hubs near renewable clusters to achieve economies of scale.

Collectively, these compliance requirements introduce operational constraints that reduce electrolyzer utilization rates and increase system complexity, exerting upward pressure on the LCOH. Mitigation strategies include hybrid renewable (solar + wind) portfolios, integration of short-duration storage, advanced digital controls for load optimization, and technology selection.

In EMDCs, project developers are increasingly adopting integrated renewable hydrogen models that include ownership of dedicated renewable energy assets. These models mitigate financier concerns around delivered electricity cost, supply security, and operational continuity by reducing exposure to competing grid uses—such as rapidly expanding data centers and other energy-intensive industries—and limiting basis, curtailment, and congestion risks. In Colombia, for instance, developers are exploring the possibility of connecting the electrolyzers to small off-grid hydroelectric plants and leveraging the regulatory advantages offered to self-generators.

Refining the Scope of Engineering, Procurement, Construction, and Optimizing Balance of Stack and Balance of Plant

Indirect CAPEX—namely, EPC, civil works, and buildings—often constitutes a significant share of total installed cost and presents opportunities for substantial savings. Containerized, plug-and-play systems—supported by robust assistance from original equipment manufacturers (OEMs) during installation and standardized skid designs—can significantly reduce the EPC scope as well as on-site labor requirements by eliminating the need for custom-built structures.

Digital-first planning and virtual commissioning have shortened delivery schedules, lowering installation costs and early-stage cash flow risk (Siemens Energy 2024a; Capgemini 2024; World Bank 2024). More broadly, clear regulations on licensing and permitting also help reduce perceived risk and transactions costs, improving project cost profiles and bankability.

BoS and BoP components—such as transformers, rectifiers, cooling systems, gas separation units, and site electrical infrastructure—are relatively mature technologies, offering less intrinsic cost reduction potential than electrolyzer stacks. Most achievable savings in these areas stem from economies of scale, design standardization, modular skid deployment, and supply chain consolidation.

Some fundamental system simplifications are also under consideration. For example, conventional alternating current grid connections require conversion to DC for electrolyzer operation, which introduces both energy losses and additional capital costs. Where DC sources dominate, such as in large-scale PV installations, direct DC coupling could eliminate these conversion losses while reducing equipment count and system complexity. Commercial-scale demonstrations are planned. Standardized plant architectures validated by independent third parties, combined with the use of digital twins, can streamline engineering processes; reduce the need for customization; and reduce site-specific adjustments for power electronics, piping, and utilities—ultimately lowering BoS/BoP costs and integration risks (Electric Hydrogen 2024b; Capgemini 2024).

Some developers pursue approaches to reduce estimated total installed CAPEX by bypassing traditional EPC contracting models, opting instead for in-house installation and project management. This approach can significantly reduce overheads associated with third-party EPC services.

Accelerating Stack Innovation

Globally, manufacturers are leveraging automation, digital quality control, and design optimization to increase production throughput, reduce labor requirements, and improve first-pass yield. Advanced gigafactory lines now integrate robotics, in-line inspection systems, and manufacturing execution systems to streamline operations. Roll-to-roll processes for membrane and electrode fabrication combine coating, drying, laminating, and cutting into continuous workflows, reducing both material handling and scrap. These innovations significantly lower unit costs: Next-generation automated lines have demonstrated order-of-magnitude output improvements and unit costs that are about 30 percent lower than semi-manual predecessors while enhancing scalability and process repeatability. Industry collaborations and EU pilot lines are working to standardize manufacturing steps, further unlocking economies of scale (Box 3.2).

BOX 3.2

ACHIEVING ECONOMIES OF SCALE IN MANUFACTURING AND DEPLOYMENT

Economies of scale are a critical driver in reducing both capital expenditure (CAPEX) and operational expenditure of electrolyzer systems. These cost reductions occur at multiple levels—manufacturing, module size, and plant scale—through shared infrastructure, automation, and process optimization.

Manufacturing scale. As production volumes increase, electrolyzer manufacturing benefits from substantial per-unit cost reductions. Higher throughput enables bulk procurement of critical materials—such as membranes, catalysts, and bipolar plates—while spreading fixed costs for research and development, factory infrastructure, and testing across larger output. Advanced automation accelerates these gains: automated stack assembly, electrode coating, sealing, and integrated quality control systems can reduce labor-intensive steps by 20–30 percent compared with manual processes (Badgett et al. 2024). Technologies such as roll-to-roll processing, laser welding, robotic handling, and emerging additive manufacturing further boost throughput, reduce waste, and improve product consistency.

A key metric underpinning these improvements is the learning rate—the percentage cost decline for each doubling of cumulative production (see also learning investment analysis box 3.3). Global estimates for electrolysis technologies range from 15 percent to nearly 32 percent (Glenk, Holler, and Reichelstein 2023; Reksten et al. 2022). These reductions are driven by automation, component standardization, and supply chain maturity, positioning green hydrogen as increasingly competitive against fossil-based alternatives.

Module size. Scaling electrolyzer modules—typically from units smaller than 1 MB to standardized 2–100 MW configurations—unlocks substantial economies of scale by enabling shared balance of plant (BoP) infrastructure. Instead of duplicating water purification, cooling systems, power electronics, and gas-processing units for multiple small modules, a single large skid can serve several stacks, reducing CAPEX per kilowatt. Increasing module size and reducing auxiliary equipment can cut investment costs by up to 80 percent as systems scale to multi-gigawatt capacity (IRENA 2024).

Standardized modules also simplify installation, reducing field labor and commissioning time by 20–30 percent, and improving logistics, through fewer, larger shipments (though modules beyond 5 MW may require special transport permits). Industry discussions indicate that transporting a 10 MW alkaline system—including the stack, gas-lye separation skid, and hydrogen purification skid—would require four high-cube 40-foot containers, whereas a comparable proton exchange membrane electrolyzer system can typically fit within a single 40-foot container. This difference underscores the importance of design optimization for transport and deployment efficiency.

BOX 3.2 *(CONTINUED)*

Operational benefits mirror these trends. Larger modules reduce the number of individual stacks, seals, and electrical connections, simplifying maintenance and enabling centralized control systems tied to shared BoP. Predictive maintenance and streamlined monitoring can lower operation and maintenance costs by 10–15 percent compared with multiple smaller units (Ramboll 2023).

Plant scale. Economies of scale at the plant level amplify cost advantages. Larger installations distribute fixed costs—engineering, permitting, and infrastructure—over greater output, reducing CAPEX per unit. Bulk procurement of electrolyzer stacks, power electronics, and BoP components lowers equipment costs, while shared infrastructure for water treatment, compression, and storage enhances efficiency.

Large plants benefit from centralized maintenance, predictive asset monitoring, and advanced power management systems, which improve efficiency and reduce electricity consumption/ kilogram of hydrogen. Digitalization and artificial intelligence (AI)-driven controls become more cost-effective at scale, optimizing load management and minimizing losses.

The impact on CAPEX is substantial: A 20 MW electrolyzer system requires only about 68 percent of the specific CAPEX of a 1 MW system; a 100 MW plant achieves about 50 percent of that baseline (EPRI 2024). These reductions, combined with operational expenditure savings from centralized operations, underscore the transformative role of scale in improving hydrogen economics.

For PEM electrolyzers, innovations target substantial reductions in the use of precious metals, especially iridium, via ultra-low-loading anodes, composite catalysts, and R2R membrane printing techniques that improve coating uniformity and enable larger-area cells. Replacing costly titanium components with corrosion-resistant coated stainless steel is advancing at high technology readiness levels (TRLs 8–9), offering CAPEX savings without compromising durability. Parallel research focuses on maximizing catalytic activity per gram of precious metal through nano-structuring (e.g., sub-5 nanometers particles, clusters, and single atoms); advanced supports; alloying; and secondary-sphere designs that leverage earth-abundant metals (nickel, cobalt, iron). Major cutting-edge advances across ALK and PEM technologies under development or early deployment are discussed below.

- **ALK capillary-fed electrolysis.** Conventional ALK electrolyzers often experience gas bubble accumulation on electrode surfaces, which increases resistive losses and reduces efficiency. Capillary-fed designs address this challenge by enabling bubble-free operation through capillary-driven water transport. Research supported by the Australian Renewable Energy Agency and commercialized by Hysata has demonstrated around 98 percent system efficiency on a higher heating value basis, with an energy requirement of only 40.4 kWh/ kgH2—significantly lower than typical commercial ALK systems (ARENA 2024; Fraunhofer 2024). Reflecting growing interest in these high-efficiency alkaline concepts, ACWA Power has announced plans to pilot Hysata's technology in Saudi Arabia (Offshore Energy 2025).

- **ALK advanced separators and diaphragms.** Reducing ionic resistance and minimizing gas crossover are critical for achieving high current density and safe pressurized operation in ALK systems. Agfa's Zirfon diaphragms, widely deployed across the industry, are scaling further with support from the EU's Innovation Fund's GIGA-SCALES (Gigawatt Scaling of Advanced Alkaline Water Electrolyzer Separators) initiative. Current development efforts focus on enhancing conductivity while reducing crossover to enable safer, higher-performance operation (Agfa 2024). Research continues to explore trade-offs between diaphragm thickness, ionic resistance, and crossover risk, as well as process conditions, such as pressure and electrolyte concentration, that define the safe operating envelope under the EN ISO 22734-1 safety standards. In parallel, zero-gap ALK electrolyzers, which press electrodes directly against the separator to minimize ohmic losses, are demonstrating performance trajectories comparable to PEM systems in laboratory and pilot settings. Milestones in the US Department of Energy's Hydrogen from Next-Generation Electrolyzers of Water program, reported in 2024, highlight progress toward liquid ALK cells operating at ≤ 2.0 volts (V) near 1 A/cm² under elevated temperatures, with some ALK models approaching operation at 1.7 V at 1.2 A/cm2. Ongoing work addresses challenges related to bubble dynamics, gas crossover, interfacial resistance, and durability at scale (DOE 2024).
- **Low-cost PEM manufacturing via membrane printing.** Tokyo Gas and SCREEN Holdings are advancing large-area, R2R, catalyst-coated membrane manufacturing, targeting multi-gigawatt annual capacity and reduced iridium loading to mitigate supply risks and lower costs. This pathway combines efficient materials use with high-throughput, digitally controlled coating to improve yield and scale (Tokyo Gas 2023). Separately, an Imperial College spin-off (M-Spin) claims that an ultra-high-surface-area metallic "electrode mat" can increase current density and lower cell voltage. This supports R&D programs to increase PEM current densities to 4 A/cm2 and above to reduce stack size and BoP requirements (Kimmel et al. 2025). Early reports suggest potential step-change gains in footprint-normalized output and cost, pending scale-up validation (Hydrogen Insight 2025b).
- **PEM replacement of titanium components.** Titanium bipolar plates and porous transport layers add cost and machining complexity. Corrosion-resistant coated stainless steel is increasingly being explored as a substitute to yield CAPEX savings at high technology readiness levels, subject to corrosion control and lifetime validation (Zhao et al. 2025).
- **PEM ultra-low-iridium anodes and composite catalysts.** Ultra-low-loading catalyst designs—leveraging nanoparticles, atomic clusters, or single-atom dispersions—aim to maximize active sites per unit of iridium while achieving loadings below 0.1–0.5 milligrams per square centimeter without compromising durability. Key strategies include using tailored supports, such as carbon, titanium, and conductive oxides; alloying with base metals to reduce precious metal content; and modifying the surface to enhance both stability and catalytic activity. Advances in AI-driven catalyst discovery and data-based durability modeling

are accelerating progress in this area, enabling faster optimization and deployment of next-generation catalyst systems (Surkus and Pham 2024).

- **PEM manufacturing automation.** High-throughput automated production lines reduce labor, scrap, and variability. Siemens Energy's Berlin gigafactory uses robotics and in-line quality control to scale PEM module manufacturing toward multi-gigawatt capacity. Fraunhofer IPT demonstrates R2R production for membrane electrode assemblies (MEAs) and continuous bipolar plate fabrication, integrating coating, drying, laminating, cutting, and laser joining to standardize processes and lower costs (Fraunhofer IPT 2024). EU-funded initiatives such as CLEANHYPRO are building shared pilot lines to industrialize stack assembly and MEA production (CLEANHYPRO 2024).

- **Integrated battery-electrolyzer concepts.** Hybrid devices such as the Battolyser combine battery storage and electrolysis in one system, storing electricity and producing hydrogen when surplus generation is available and delivering electricity back to the grid during shortages. A 1 MW pilot system has been installed at RWE's Magnum power plant in Eemshaven, the Netherlands, with manufacturing moving toward larger skids/modules for rapid deployment (Battolyser Systems 2024).

Although the electrolyzer stack represents less than half of total CAPEX, it remains the primary focus of manufacturing innovation and R&D. Advances in catalyst formulations, material science, and stack design are central to reducing costs while improving efficiency and durability.

Across electrolyzer technologies, multiple development pathways are targeting gains in electrical efficiency on the order of 20–30 percent over current practice. These improvements would bring energy consumption closer to the thermodynamic limit for hydrogen production, which is 33.4 kWh/kg on a lower-heating-value basis (39.4 kWh/kg on a higher-heating-level basis)—well below today's typical range of 50–55 kWh/kg. Achieving this step change in performance will require breakthroughs in electrode architecture, ionic transport optimization, and thermal management, supported by scalable manufacturing processes.

Digitalizing Across the Project Life Cycle

Digital asset management and predictive maintenance are becoming integral to improving project bankability in renewable hydrogen systems. Commercial operators, such as Lhyfe in partnership with IBM Maximo, are deploying AI-enabled asset management platforms to monitor system health, reduce unplanned downtime, and extend electrolyzer stack life. Research initiatives like the US Department of Energy's Hydrogen from Next-Generation Electrolyzers of Water program are leveraging machine learning to analyze large degradation data sets, enabling optimization of operating envelopes and refinement of stress testing protocols. These approaches enhance confidence in lifetime performance, reduce uncertainty in refurbishment cycles, and contribute to more accurate financial modeling of long-term operational costs (Lhyfe 2024).

At the plant level, the adoption of standardized system architectures, model-based design methodologies, and digital twin technologies is significantly improving design accuracy and integration efficiency. These tools help prevent oversizing, reduce engineering errors, and streamline system integration. Analyses suggest potential reductions in the LCOH of 9–12 percent through better design decisions and process optimization (Siemens 2025). Furthermore, virtual commissioning and advanced 3D integration tools will accelerate project timelines and reduce on-site labor requirements. In the operational phase, AI-enabled predictive maintenance is emerging as a critical lever for cost optimization. By extending electrolyzer stack lifetimes, minimizing unplanned downtime, and dynamically adapting operations to renewable generation variability and tariff structures, these solutions can reduce operational expenditure (OPEX). Machine learning models that analyze degradation mechanisms are enabling the definition of optimized operating envelopes, further enhancing durability and performance.

AI is also transforming R&D, accelerating catalyst discovery, and compressing development timelines from years to hours through in-silico simulations. These advances have the potential to deliver spillover benefits in material cost reduction and performance improvement, reinforcing the competitiveness of next-generation electrolyzer technologies (EVOLOH 2024; Capgemini 2024; Enapter 2025).

Reducing Financing Costs

In EMDCs, lenders prioritize proven, bankable technologies supported by robust operational track records, warranties, and performance guarantees. Debt providers favor ALK and PEM systems; SOEC and AEM solutions—though promising—may require additional de-risking via credit enhancements, guarantees from OEMs, and longer demonstration periods to achieve similar bankability.

The debt-to-equity ratio for hydrogen projects often reflects revenue uncertainty and technology risk. Unlike mature renewables (such as utility solar PV), where leverage of 90 percent debt is sometimes feasible, early-stage hydrogen plants frequently carry lower leverage, with ratios closer to parity between debt and equity. This low debt ratio increases the weighted average cost of capital (WACC) and underscores the importance of risk mitigation and strong offtake arrangements (World Bank 2024).

To reduce financing costs and improve access to debt in EMDCs, developers are increasingly considering a set of risk mitigation measures focused on technology and contractual structuring. Key strategies include the following:

- **Fixed-price EPC contracts with liquidated damages.** Engaging creditworthy EPC contractors under fixed-price agreements provides cost certainty and allocates construction risk. Liquidated damages clauses further protect lenders by ensuring compensation for delays or performance shortfalls.

- **OEM warranties and performance guarantees.** OEMs offering robust warranties, availability commitments, and performance guarantees—ideally supported by insurance—enhance confidence in long-term operational reliability and reduce perceived technology risk.
- **Comprehensive project insurance.** Tailored insurance packages, including construction all risk, delay in start-up, business interruption, and equipment breakdown coverage, address hydrogen-specific risks and strengthen the project's risk profile for financiers.
- **Export credit agency (ECA) support.** Leveraging ECA-backed financing for eligible equipment and services can extend loan tenors and reduce interest margins, improving overall project bankability and lowering the cost of capital.

Collectively, these measures help de-risk projects, improve lender confidence, and enable more favorable financing terms, which are critical for scaling renewable hydrogen deployment in EMDCs

Developing Common user Infrastructure

The development of regional hydrogen hubs—where multiple production, storage, and distribution projects are co-located and integrated—can reduce both CAPEX and OPEX. By leveraging shared infrastructure, economies of scale, and operational synergies, hubs create a cost-efficient and resilient ecosystem for renewable hydrogen deployment. They are characterized by the following features, among others:

- **Shared infrastructure.** One of the most significant advantages of clustering is the ability to share large-scale infrastructure across multiple projects. Doing so reduces both EPC premiums and the CAPEX associated with assets such as high-voltage transmission lines to evacuate renewable energy; hydrogen pipelines; and storage facilities (including salt caverns or pressurized tanks, if required). Infrastructure that supports offtake, such as compression stations and offtake terminals, can be developed once and used by several producers and consumers, eliminating the need for redundant, project-specific investments and reducing up-front capital requirements
- **Economies of scale.** Aggregating demand within a hub enables the deployment of larger production and storage facilities, which benefit from scale efficiencies. Bulk procurement of standardized equipment and standardized engineering designs drive down per-unit capital costs and shorten construction timelines. Larger systems also tend to exhibit better performance characteristics, improving overall asset utilization.
- **Streamlined permitting and land use.** Co-location simplifies planning and regulatory processes. Integrated environmental impact assessments, consolidated permitting applications, and unified stakeholder engagement reduce administrative overheads and accelerate project schedules. It also streamlines negotiations for land acquisition and rights-of-way, lowering indirect CAPEX and shortening delays.

- **Optimized operation and maintenance (O&M).** Hubs enable resource pooling for O&M, reducing staffing requirements and inventory carrying costs. Integrated digital platforms for predictive maintenance and energy management enhance reliability and reduce downtime, lowering variable OPEX.
- **Favorable policy and financial incentives.** Governments often prioritize hydrogen hubs through targeted incentives, including capital grants, tax credits, transmission charge waivers, and accelerated permitting. These measures directly reduce both CAPEX and OPEX while improving project bankability and investor confidence.

Regional hydrogen hubs represent a strategic and economically compelling model for scaling renewable hydrogen deployment. By co-locating production, storage, and distribution assets, hubs unlock substantial reductions in both CAPEX and OPEX through shared infrastructure, economies of scale, and streamlined permitting processes. These integrated ecosystems not only minimize redundant investments in high-cost assets such as transmission lines, pipelines, and storage facilities, they also accelerate project timelines and improve operational efficiency through resource pooling and advanced digital management systems. Clustering projects within designated hubs positions developers to capture favorable policy incentives, enhancing financial viability and investor confidence. Collectively, these benefits make hydrogen hubs a cornerstone for achieving cost competitiveness, reliability, and rapid market penetration in the emerging hydrogen economy.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IV. Electrolyzer Manufacturers and their Offerings

Key Points

- Electrolyzer manufacturers distinguish themselves by the technology they deploy—alkaline (ALK), proton exchange membrane (PEM), solid oxide electrolyzer cell (SOEC), and anion exchange membrane (AEM)—and the structure and breadth of their commercial offerings. These offerings span the scope of supply—from stack-only to turnkey engineering, procurement, and construction (EPC) delivery to long-term service agreements (LTSAs), performance guarantees, operator training, and ownership models.
- Bankable hydrogen projects require original equipment manufacturers (OEMs) to provide verifiable operational data on a commercial scale. Long-standing corporate presence alone does not promise or prove reliability. Instead, metrics such as cumulative megawatts deployed, years of validated performance under LTSAs, and third-party verification become critical markers of technological maturity, which create lender confidence.
- A few electrolyzer manufacturers have proved themselves in large-scale hydrogen projects, underscoring the need for robust technical due diligence and verification of real operating data prior to procurement.
- LTSAs are becoming standard practice. Durations of 5–10 years are common for ALK and PEM systems, while 2–5 years are often seen for emerging technologies. LTSAs cover preventive and predictive maintenance, stack refurbishment, spare parts, and availability guarantees—often backed by liquidated damages for underperformance.
- Standard product warranties usually last 12–24 months, with optional extensions. Performance guarantees linked to key performance indicators (KPIs)—such as system efficiency, hydrogen output, uptime, and degradation rates—are embedded in LTSAs, aligning technology performance with project cash flow models and mitigating operational revenue risk.

- OEMs are integrating multitiered training programs into their service portfolios to strengthen operational competence, safety, and reliability—critical factors in due diligence and insurance assessments.
- Beyond direct equipment sales, OEMs and developers are experimenting with leasing and tolling (“hydrogen as a service”) models. Leasing reduces up-front capital expenditure (CAPEX) while maintaining OEM involvement; tolling models shift project economics toward operational-expenditure-based hydrogen procurement, offering flexibility for industrial users and expanding the market beyond traditional owner-operator structures.

This chapter covers the commercial offers put forward by electrolyzer companies. It analyzes: (1) their market presence and operational track record, (2) the scope of equipment and services on offer, (3) the structure of the LTSA, (4) their warranty and performance guarantees, (5) their training services, (6) their delivery time frames and commitments, and (7) their ownership models. It will also highlight leading players across global markets.

Market Presence and Operational Track Record

An OEM’s longtime market presence does not necessarily translate into mature and reliable electrolyzer systems. Corporate operations may span years, but their systems are not necessarily better under operational conditions seen in today’s markets. At the same time, firm longevity in related sectors, such as chloralkali, does testify to experience with engineering and process control. Technology-specific field data must nevertheless be available to assess reliability going forward.

Bankable projects require OEMs to demonstrate operational history at scale, validated through commissioning records and performance data. Developers have learned from difficult experience the risks of scanty track records (Fuel Cell China 2025). Sinopec’s Kuqa project, for example, performed at a third of expected output. By contrast, Sinopec’s recent Ordos tender signals a mature approach, requiring documented industrial-scale delivery and verified operating hours as prerequisites for participation.

It is important as well to distinguish between corporate reputation on the one hand and evidence of asset-specific operations on the other. ALK electrolyzer OEMs, benefiting from more than five decades of deployment, naturally possess the deepest cache of long-term data, extending beyond 30 years in some instances. These data affirm their stability and operational durability and confer confidence in their systems’ longevity and maintenance profiles.

PEM electrolyzer OEMs, although relatively newer, have accumulated 10–20 years of operational data from pilot projects, demonstration plants, and commercial deployments. They have demonstrated robust performance in applications demanding high responsiveness, fast ramping, and high-purity hydrogen output, which are crucial for renewable energy integrations. Their field records—documenting thousands of operational hours—validate key reliability indicators and reinforce their suitability for dynamic grid-balancing services and decentralized hydrogen production.

Emerging technologies such as SOEC and AEM electrolyzers are still in the developmental and demonstration stages. Comparatively immature, they have limited operational lifetime data—often fewer than five to seven years. Ongoing research and development, meanwhile, is focusing on the durability challenges inherent to high-temperature operation (in the case of SOEC) or membrane stability (for AEM). This limited field performance history constrains their deployment in large-scale, long-term projects, although their potential for high efficiency and operational flexibility is promising.

Procurement committees have a practical way to translate "years operating" into bankability by weighting: (1) total years since first commercial electrolyzer delivery, (2) cumulative megawatts deployed by technology, (3) years of demonstrated LTSA performance at or above guaranteed KPIs, and (4) the breadth of third-party-verified references. On that basis, Nel and thyssenkrupp nucera score highly on ALK longevity; Siemens Energy and ITM offer the longest continuous PEM track records in Europe; Accelera benefits from the Hydrogenics legacy and the Cummins service infrastructure; John Cockerill demonstrates scale in pressurized ALK references; LONGi is young but scaling fast; and Topsoe, Bloom, and Sunfire anchor the SOEC frontier with credible, but still maturing, lifetime data sets. Where data are newer (e.g., 2020-era PEM or 2021-era Chinese ALK), sponsors can compensate via LTSA-tied availability and efficiency guarantees, prepositioned spares, and step-down pricing on early stack replacements.

"Years operating" is not a proxy for risk. What matters is technology-specific years with verifiable KPIs under commercial duty. Mature ALK suppliers bring the deepest historical baselines; leading PEM OEMs offer a decade of grid-interactive experience; SOEC leaders are highly efficient under baseload heat but with shorter lifetimes; and Chinese manufacturers bring rapid cost-scale advantages with shorter non-domestic track records. Mapping those profiles to the duty cycle, standards regime, and financing covenants—then hard coding the outcomes into warranties, LTSAs, and liquidated damage (LD) schedules—is the most reliable way to convert OEM history into bankable performance.

Tables 4.1 and 4.2 show three useful parameters for assessing track records of the leading OEMs, based on operational capacity, for ALK and PEM electrolyzers. These are: (1) electrolyzer capacity in operation, (2) electrolyzer capacity under construction, and (3) the year the company started its hydrogen business segment.

TABLE 4.1

Largest ALK electrolyzer OEMs and their track records, as of June 2025

COMPANY (PARENT)	OPERATIONAL (MW)	UNDER CONSTRUCTION (MW)	YEAR H_2 BUSINESS ESTABLISHED	COUNTRY
LONGi	283	407	2021	China
John Cockerill	251	292	2019	China
Peric	196	151	2013	China
thyssenkrupp nucera	100	3,220	2015	Germany
nel	79	120	1927	Norway
SUNGROW Clean power for all	46	887	2021	China
ENVISION	28	528	2022	China
Hydrogen pro	6	320	2013	Norway

Source: S&P 2025b. LONGi information provided by OEM.

Note: ALK = alkaline; H2 = hydrogen; MW = megawatt; OEM = original equipment manufacturer.

TABLE 4.2

Largest PEM electrolyzer OEMs and their track record, as of June 2025

COMPANY (PARENT)	OPERATIONAL (MW)	UNDER CONSTRUCTION (MW)	YEAR H_2 BUSINESS ESTABLISHED	COUNTRY
SIEMENS energy	141	1,000	2011	Germany
plug	135	161	2017	United States
accelera	74	95	2023	United States
ITM POWER	46	244	2001	United Kingdom
nel	43	0	1927	Norway
ELECTRIC HYDROGEN	10	200	2020	United States
BriHyNergy	3	0	2021	China

Source: Based on S&P 2025b . Siemens Energy information provided by OEM

Note: H2 = hydrogen; MW = megawatt; OEM = original equipment manufacturer; PEM = proton exchange membrane.

Types of Offers and their Scope

OEMs can provide three types of offers based on the system scope they can offer to their customers.

- At the base level, stack-only suppliers deliver the electrolyzer machine, while leaving the balance of stack (BoS) and balance of plant (BoP) integration to the buyer or EPC partner.
- At the midlevel, providers supply the electrolyzer stack, BoS, and BoP in a containerized or skid-mounted system to project developers or EPC contractors.
- At the most comprehensive level of plant delivery are the OEMs that provide EPC and turnkey solutions, which include the electrolyzer system, power system integrations, and construction.
- Most of the large OEMs mentioned in the electrolyzer manufacturing section above are now providing offers at the third level. Table 4.3 contains a list of sampled OEMs and the highest type of offer they can provide.

TABLE 4.3

Scope of selected electrolyzer companies' offerings

OEM	OFFERINGS REPORTED	INFORMATION LINK	OEM	OFFERINGS REPORTED	INFORMATION LINK
LONGi	2	Click here	thyssenkrupp nucera	3	Click here
SUNGROW Clean power for all	3	Click here	plug	3	Click here
Peric	2	Click here	EVOLOH	1	Click here
TRINA GREEN HYDROGEN	2	Click here	ITM POWER	3	Click here
THE	2	Click here	ENVISION	3	Click here
John Cockerill	3	Click here	AsahiKASEI	1	Click here
SIEMENS energy	2	Click here	Kanadevia Technology for people and planet	2	Click here
nel	3	Click here			

Source: OEMS' MARKETING MATERIAL.

Note: OFFERINGS: 1= STACK; 2 = STACK + BOS + BOP; 3 = STACK + BOS + BOP + EPC. BOP = BALANCE OF PLANT; BOS = BALANCE OF STACK; EPC = ENGINEERING, PROCUREMENT, AND CONSTRUCTION; OEM = ORIGINAL EQUIPMENT MANUFACTURER.

Long-term Service Agreements

OEMs offer LTSAs as a central component of their business models, delineating contractual obligations between the OEM and the project owner. Across the sector, the duration of the agreement averages from 5–10 years for ALK and PEM; for AEM and SOEC the duration averages two to five years. Under an LTSA, irrespective of the technology, OEMs normally commit to cover preventive and predictive maintenance, remote monitoring, stack refurbishment, guaranteed spare-part availability, and performance guarantees, ensuring operational reliability. Many LTSAs also include LDs if targets are not met, shifting some operational risk back to the OEM.

Preventive maintenance involves scheduled interventions such as replacing seals, membranes, or filters; cleaning water treatment systems; inspecting electrical components; and recalibrating control systems, typically performed at fixed intervals to minimize wear-related failures. By contrast, predictive maintenance leverages digital monitoring, sensors, and OEM-provided analytics to anticipate failures before they occur, enabling condition-based interventions. For example, Nel Hydrogen offers cloud-based diagnostics that monitor deviations in stack voltage to predict degradation, while Siemens Energy integrates Supervisory Control and Data Acquisition (SCADA)-linked predictive algorithms into its Elyzer P-300 PEM systems, allowing operators to plan stack replacements.

Intertwined with maintenance is remote monitoring, or the continuous oversight of performance, safety, and efficiency across distributed assets. Using SCADA systems, Internet of Things sensors, and cloud-based platforms, OEMs can track stack voltage, current density, water quality, pressure, and gas purity in real time. Deviations from baseline values can trigger predictive maintenance alerts, which allow operators to intervene before failures escalate into costly downtime. Beyond operational reliability, remote monitoring reduces the need for on-site staff, lowers operation and maintenance (O&M) costs, and supports standardized benchmarking across multisite portfolios.

Refurbishment affects key components such as frames, bipolar plates, and BoS hardware, and the replacement of membranes, catalysts, seals, and diaphragms instead of discarding entire stacks at end of life. This approach can reduce replacement CAPEX by 20–40 percent compared with the cost of procuring new stacks, alleviating downtime, and extending the useful life of the installation. OEMs are beginning to formalize refurbishment within LTSAs: see, for example, thyssenkrupp nucera's stack refurbishment in its 360° Lifecycle Service.

OEMs increasingly commit to secure spare part availability by guaranteeing that essential components remain in stock—such as membranes, seals, catalysts, rectifiers, and water purification modules—either through on-site consignment inventories or regional service hubs. LTSAs assure that OEMs will make critical parts available within fixed lead times (e.g., 48–72 hours for critical components). For example, Nel Hydrogen integrates consignment stock strategies into its predictive maintenance framework to support 95 percent + availability.

Examples of LTSAs from selected OEMs are offered below:

- Siemens Energy bundles its Elyzer P-300 PEM units with LTSAs that include digital twins, availability tracking, and uptime guarantees, as well as spare part guarantees if performance falls short.
- thyssenkrupp nucera's life-cycle portfolio combines preventive, corrective, and predictive maintenance with refurbishment services such as stack recoating and reinstallation (thyssenkrupp nucera 2024).
- Plug Power's GenCare program offers predictive maintenance and availability guarantees (Plug Power 2024).
- Topsoe provides LTSA packages for its SOEC systems that guarantee uptime and conversion efficiency (Topsoe 2025).
- Electric Hydrogen is also covering stack refurbishment or replacement, recognized as a midlife cost driver, reflecting industry acknowledgment that stacks are consumable assets (Electric Hydrogen 2024a).

Benchmark costing of an LTSA typically combines fixed O&M fees with stack replacements—in the case of PEM, for example, often achieving 15–20 percent of the stack's CAPEX. Electric Hydrogen reports fixed O&M costs of $45–$54/kW per year, with stack replacements representing 15–20 percent of installed cost (Electric Hydrogen 2024a). Academic sources estimate O&M costs typically within the low single-digit percentage range of CAPEX, while stack replacement is treated as a separate budget item. This distinction ensures greater financial clarity and predictability for developers.

Practical examples demonstrate the mainstream adoption of LTSAs. For example, Siemens Energy has signed multiple 10-year service contracts in Germany, including for the 100 MW Hamburg Renewable Hydrogen Hub (Siemens Energy 2024b, 2024c). HydrogenPro secured a 10-year agreement for its 220 MW contribution to the Advanced Clean Energy Storage (ACES) Delta project in Utah. In the United Kingdom, ITM Power included LTSA commitments in its offer of a PEM 20 MW electrolyzer for the Hydrogen Allocation Round 1 (ITM Power 2025).

Warranties and Performance Guarantees

Warranties and performance guarantees are contractual commitments that ensure electrolyzer systems meet specified operational and quality standards over a defined period. While both provide risk mitigation, they address different dimensions of project assurance.

An OEM's standard product warranty is a contract that ensures the equipment is free from defects in design, components, materials, and workmanship. It protects the customer against manufacturing flaws or system component failures, obliging the OEM to repair or replace affected parts at no cost. Standard warranty periods in the electrolyzer industry range from 12 to 24 months, starting from either shipment or commissioning depending on jurisdiction and contract terms. For example, Siemens Energy, ITM Power, and Plug Power offer 12 months from initial operation.

In the nascent market, OEMs are offering extended warranties. In 2025, Enapter announced that all systems shipped after January 1, 2025, could be covered for up to five years, with a standard one-year warranty and optional extensions available at additional cost. It should be noted that such coverage is conditional on proper commissioning within three months of delivery and strict adherence to prescribed O&M protocols. These conditions demonstrate how OEMs are using extended warranties both to offer stronger assurances to customers and to manage their own operational risk exposure.

The OEM contractually commits to performance guarantees with reference to key indicators. Specified operational outcomes are then delivered over a defined period. These guarantees are expressed through quantifiable indicators such as system efficiency (kilowatt-hours per kilogram of hydrogen [kWh/kgH2]), hydrogen production capacity, plant availability (uptime percentage), and degradation rates (millivolts per kilo-hour [mV/kh]). In practice, performance guarantees are often embedded within the LTSA, with a fixed duration of the contract timeline. If the system underperforms (e.g., produces less hydrogen, operates less than a certain percentage uptime), the OEM is typically required to either restore performance, extend corrective services, or provide financial compensation through LDs. For project developers and financiers, these guarantees are a critical safeguard, aligning technology performance with financial models and protecting against revenue shortfalls, thereby reinforcing the overall bankability of the project. For example, Siemens Energy offers configurable agreements that range from basic maintenance to premium O&M programs, with embedded performance guarantees to reduce asset-owner risk (Siemens Energy 2024a).

Training Services

Operator training has become a key differentiator in the selection of an OEM. Technology providers are with increasing frequency embedding training into LTSAs and commissioning packages. Training services are a critical part of electrolyzer project deployment, ensuring that operators, engineers, and maintenance staff can safely and efficiently manage complex hydrogen production systems. Well-trained operators reduce downtime, extend asset lifetimes, and safeguard safety standards. Ensuring high-quality training is a due diligence factor in contracts and financing, and a growing dimension of competitiveness for OEMs.

Electrolyzer OEMs typically provide multitiered training packages, each aligned with milestones:

- **Pre-commissioning.** This training occurs in the classroom or through virtual sessions that cover system fundamentals, safety protocols, and operational procedures. It targets site managers and technical teams waiting for equipment to arrive.
- **On-site commissioning.** This is practical, hands-on training concurrent with installation and start-up. It focuses on the Human-Machine Interface (HMI) while troubleshooting issues that pop up at commissioning and undertaking routine maintenance.

- **Advanced O&M.** OEMs offer extended programs on predictive and preventive maintenance, stack replacement procedures, water- and gas-quality monitoring, and integration with BoP.

For mature ALK technologies, thyssenkrupp nucera integrates training into its LTSA portfolio. Classroom, remote, and hands-on modules are all deployed to strengthen operator competence across the life cycle. For example, Siemens Energy has formalized training with its "H2 Elyzer P-300 Familiarization and Operations" course that institutionalizes training in a scalable and repeatable framework. For newer technologies (e.g., AEM electrolysis), Enapter treats training like a tool that empowers integrators. The topics of its courses range from safety protocols to hands-on operations to cultivate an ecosystem of capable developers (Enapter 2025). Similarly, Quest One (formerly H-TEC SYSTEMS) emphasizes training as a milestone for commissioning.

Delivery Fime Frames and Commitments

In their dealings with emerging markets and developing countries, electrolyzer OEMs quote delivery times of 12–18 months for standard modules. But delivery times differ according to technology, manufacturing capacity, and project scale. Deliveries for large utility-scale projects often exceed 24 months, and commitments are made under general international commercial terms, which define the point at which risk and responsibility transfer from the OEM to the buyer. For example, European OEMs such as Siemens Energy and thyssenkrupp nucera often use FCA (Free Carrier) Germany, in which the buyer manages onward transport, insurance, and import clearance. Asian suppliers such as LONGi Hydrogen and Sungrow offer CIF (cost, insurance, and freight) to reduce logistical complexity for international buyers.

Ownership Models—Direct Sales, Leasing, and Tolling

Beyond system integration, OEMs also differentiate themselves through ownership models. Under the direct-sale model, customers purchase systems outright, assuming operational risks and retaining maximum control. This approach is favored by stakeholders who have sought custom projects. For example, for the Normand'Hy project (200 MW PEM), Siemens Energy is delivering the Elyzer P-300 units under a direct equipment sale, but Air Liquide owns and operates the asset. Under the leasing model, OEM or a financial intermediary retains ownership of the electrolyzer and leases it to the operator for a monthly/annual fee. This reduces up-front CAPEX for the user but requires long-term operational expenditure commitments. An example of this model is Plug Power's partnership with GTL Leasing, which illustrates how this model accelerates deployment by reducing up-front capital requirements (Plug Power 2024). By contrast, the tolling model resembles a processing-as-a-service model: the OEM, project developer, or third-party owns the electrolyzer asset and sells hydrogen to the customer at an agreed $/kg price. This mirrors the structure of a tolling or power purchase agreement. ENGIE has piloted "hydrogen-as-a-service" contracts in which industrial users avoid CAPEX and purchase green hydrogen from electrolyzers that ENGIE installs and operates on site.

Tools to Support OEM Due Diligence

The information discussed in this chapter emphasizes that as hydrogen project developers move from conceptual designs to real-world delivery, vendors, systems, and manufacturing practices undergo a rigorous evaluation. Evaluations are essential in addressing risk at execution, aligning cost expectations, and strengthening lender confidence. Thus, a due diligence process grounded in real-world operational and installation realities is a critical tool to bridge the gap between nominal EPC offerings and the actual requirements for safe, reliable, and grid-compliant hydrogen production assets.

In order to perform comprehensive due diligence, it is critical to have a framework that includes diverse evaluation tools and abilities. The layers are interconnected and can include everything from business practices to operations and management, equipment, safety and compliance, commissioning, and O&M strategies.

A range of companies offer their expertise in the performance of due diligence. They have comprehensive frameworks that can evaluate everything from technology fit to performance under variable renewable power, water and utility integration, grid interface, and site constraints. The aim is to optimize the levelized cost of hydrogen, de-risk delivery schedules, and support procurement and vendor selection (Box 4.1).

BOX 4.1

DET NORSKE VERITAS (DNV) DUE DILIGENCE PARAMETERS

DNV maintains a structured database to support technology due diligence for electrolyzer projects, drawing on assessments of operational and pipeline projects. The framework covers technical performance, safety and compliance, controls, quality, and life-cycle considerations, and can be coupled with feasibility and bankability reviews to inform investment decisions.

Framework for Parameters (sample structure)

Business evaluation (4 parameters): Commercial maturity and supplier references, performance guarantees, warranty/after-sales support, delivery schedule, and spares strategy.

Equipment overview

General (10 parameters): Technology type, nominal capacity range, footprint, utilities (power, water, cooling), operating envelope (pressure/temperature), modularity, and integration options.

BOX 4.1 *(CONTINUED)*

Cell design (4 parameters): Stack architecture, electrodes/membrane/diaphragm materials, current density/voltage range, and degradation mechanisms.

Balance of plant (6 parameters): Gas-liquid separation, purification/drying, water treatment, thermal management, compressors/pressurized operation, and venting/purging systems.

Electrolyzer operational evaluation

Performance (11 parameters): Includes specific energy consumption, efficiency curves across loads, turndown range, start-up/shut-down dynamics, ramp rates, and steady-state/stochastic variability.

Thermal management and reliability (7 parameters): Includes heat rejection, warm/cold standby strategy, cycling effects, component Mean Time Between Failures (MTBF), and fault tolerance.

Lifetime (7 parameters): Stack life and replacement strategy, catalyst poisoning risks, calendar vs. cycle aging, and performance fade rates.

Rectifier/transformer operational performance (>7 parameters): Alternating current (AC)/direct current (DC) conversion efficiency, harmonic distortion and grid code compliance, dynamic response under variable renewable input, and redundancy and protection schemes.

System monitoring and controls (>27 parameters): Control philosophy, Supervisory Control and Data Acquisition (SCADA) integration, data logging and alarms, cybersecurity policies, remote diagnostics, performance reporting, and test protocols.

System safety and compliance (19 parameters): Includes design compliance with applicable codes and standards; hazardous area classification; Hazard Identification (HAZID)/Hazard and Operability Study (HAZOP) coverage; functional safety (Safety Instrumented System [SIS]/Safety Integrity Level [SIL]) concept; pressure relief and venting; emergency shutdown; fire and gas detection; oxygen/hydrogen management; occupational health and environmental controls.

Quality and manufacturing (13 parameters): Includes quality assurance/quality control processes, supplier qualification, traceability, factory acceptance tests, continuous improvement, and nonconformance handling.

Installation and commissioning (3 parameters): Site requirements, commissioning procedures and performance verification, as-built documentation, and training.

Service, maintenance, and warranty review (>9 parameters): Operation and maintenance strategy and intervals, condition monitoring, spare parts logistics, warranty scope and exclusions, and performance guarantee enforcement.

In conclusion, OEM offerings vary widely. Various commercial and service factors must be considered for optimal electrolyzer procurement. Buyers should evaluate offers not only on headline efficiency or stack and cost specifications, but on the full set of technical, operational, and financial factors that determine long-term project value.

Project design is also shaped by external constraints. Financing requirements—including the need to use established EPC contractors or proven OEM technologies—can limit flexibility in system selection and raise overall project costs. In addition, policy frameworks, such as local content rules, manufacturing incentives, or eligibility criteria for public support, can influence technology choices and procurement strategies. Continuous capacity building among financial institutions and public stakeholders remains essential to keep pace with rapid advances in electrolyzer technologies.

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