U.S. DEPARTMENT OF ENERGY

UPDATE 2024

Pathways to Commercial Liftoff: Clean Hydrogen

DECEMBER | 2024

Comments

The Department of Energy welcomes feedback on this report. Please direct all inquiries and input to liftoff@hq.doe.gov. Please note that the information provided is subject to the Freedom of Information Act and should not include business-sensitive or non-public information.

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Context

The U.S. Department of Energy (DOE) has published a series of Liftoff Reports—living documents that serve as a shared fact base on the development, deployment, and commercialization of clean energy technologies, like clean hydrogen. The Liftoff Reports build upon deep industry and community engagement, learnings from DOE investments and initiatives, and input from other public sector organizations. They analyze both challenges and opportunities in the acceleration of our energy transition in an effort to align and catalyze action.

In March 2023, the DOE published its first *Pathways to Commercial Liftoff: Clean Hydrogen* Report. DOE reported that clean hydrogen[1] can reduce U.S. carbon emissions by up to 10% by 2050,[2] particularly in sectors without other cost-effective decarbonization options, such as ammonia production and heavy-duty transport. Clean hydrogen reaches liftoff when it becomes cost competitive with fossil-based hydrogen or other carbon-intensive alternatives at the point of consumption for a sustained period of time.

Overall, the clean hydrogen economy is poised to achieve liftoff by 2030, although the timing of liftoff varies by end use application. Industrial and chemical use cases—such as ammonia and petrochemical production, in which production can be co-located with utilization—might see near-term expansion by 2026. Mobility and transportation use cases, such as heavy- and medium-duty trucking, might require additional cost reductions and infrastructure build-out so that liftoff can occur in the 2030s.

Over the last year, tailwinds and headwinds have emerged that affect the pathways and timing for clean hydrogen's commercial liftoff. This 2024 report update summarizes those dynamics and provides an updated fact-based view as to how the United States can scale its clean hydrogen economy.

Except where noted, the analysis in this report was completed following the publication of the Notice of Proposed Rulemaking (NPRM) for the clean hydrogen production tax credit (IRA 45V), but prior to the publication of the final rules, which were issued by the United States Treasury Department and Internal Revenue Service on January 3, 2025. The final rules include provisions that provide increased flexibility and investment certainty for clean hydrogen producers. For instance, compared to the proposed rules, the final rules:

- Extend the annual matching transition rule so that producers are not required to match electricity consumption on an hourly basis until 2030, two years later than under proposed regulations; and allow qualifying producers to use hour-by-hour accounting to determine emission rates for electricity rather than an annual average;
- Add new pathways to demonstrate incrementality, including the use of electricity generated from nuclear facilities that are at risk of retirement and the use of electricity generated in states with robust greenhouse gas emissions caps and clean (or renewable) electricity standards;
- Include additional pathways using natural gas alternative feedstocks, such as renewable natural gas (RNG) derived from animal manure, wastewater treatment plants, or coal mine methane;
- Indicate that hydrogen can use supplier-specific upstream methane emissions rates reported to EPA's Greenhouse Gas Reporting Program starting in 2026, so long as EPA maintains robust reporting requirements; and
- Allow producers to lock in the version of 45VH2-GREET available when a facility commences construction for the duration of the credit eligibility period.

The impact of the final rules will be reflected in future Liftoff reports.

1 Except where noted, in both *Pathways to Commercial Liftoff: Clean Hydrogen* (March 2023) and this 2024 report update, "clean hydrogen" refers to hydrogen with lifecycle emissions less than 4 kg CO_2e/kg H_2. Carbon dioxide equivalent, or CO_2e, refers to the impact of different greenhouse gases, represented in the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of those other greenhouse gases.

2 Compared to 2005 levels.

Executive Summary

Since the March 2023 publication of *Commercial Liftoff: Clean Hydrogen*, there have been several changes that impact projections for a U.S. clean hydrogen economy. This 2024 report update summarizes the following key topics:

1. ***Updates to project momentum.***

   Over the last year, total announced clean hydrogen production capacity has increased 26% to 14 million metric tons per annum (MMTpa) based on private sector announcements. This increase does not include the additional 3 MMTpa target capacity from DOE's Regional Clean Hydrogen Hubs (H2Hubs). Investment in clean hydrogen has nearly doubled in the last year—not including the approximately $50 billion of capital associated with DOE H2Hubs—shrinking the amount of additional capital investment required to achieve liftoff by 30-60%, to $30-150 billion from the $85-215 billion gap reported in Commercial Liftoff: Clean Hydrogen (March 2023). Most project development activity has occurred earlier in the project development funnel, with comparatively less development in later stages. Few projects have advanced to final investment decision (FID) due to increased production costs (discussed in Section 2), anticipation of a final rule for the Inflation Reduction Act's 45V Tax Credit (45V)[3] and lack of offtake agreements. Nevertheless, even assuming no new announcements in 2025 for projects that could reasonably come online by 2030, the United States is on track to reach 7-9 MMTpa in operational capacity by 2030.

2. ***Updates to production costs.***[4]

   Cost estimates for electrolytic hydrogen production have increased from $3-6/kg to $5-7/kg (exclusive of 45V tax credits). Compared to estimates in *Commercial Liftoff: Clean Hydrogen (March 2023)*, developers in 2024 face higher costs associated with electrolyzer installation, clean electricity and financing, in addition to plant design adjustments needed to meet the requirements to qualify for the 45V tax credit. Low-carbon reformation-based hydrogen[5] production cost estimates have increased from $1.6/kg to $2/kg—exclusive of 45V and 45Q tax credits—primarily due to increases in installation, electricity, and financing costs. Many of these cost drivers for clean hydrogen production are transitory; costs are projected to decline as electricity prices drop, as electrolyzer capex decreases, and as interest rates and other inflationary pressures abate. Present-day levelized production costs of unabated fossil-based reformation have stayed and are projected to remain relatively stable, ranging between $0.9-1.2/kg.

3. ***Refreshed view of applications.***

   Despite increases in cost estimates over the last year, markets exist for different clean hydrogen production pathways. Given their lower production costs relative to electrolysis projects, low-carbon reformation projects can target large, industrial offtakers in the chemicals and refining spaces and replace current demand—10 MMTpa in the United States—for unabated fossil-based hydrogen. Electrolysis projects can target emerging applications in which end users might have a higher willingness to pay or can stack additional incentives. These applications include clean fuels in states or countries with low-carbon fuel standards. Export markets with demand subsidies could also play an increasingly important role in clean hydrogen production scale-up.

4. ***Promising production pathways.***

   Additional clean hydrogen production pathways like methane pyrolysis and geologic hydrogen could play a meaningful role in the commercial liftoff of clean hydrogen, although their respective market sizes and carbon intensities are still to be determined.

3 The United States Department of Treasury published its Notice of Proposed Rulemaking (NPRM) for the Clean Hydrogen Production Tax Credit (45V) in Internal Revenue Code § 45V of the Inflation Reduction Act in December 2023. See Internal Revenue Service, "Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property," Proposed Rule (December 26, 2023). Final rules were announced on January 3, 2025, which will have a meaningful impact on project development and production costs. Except where noted, however, analyses related to tax credits in this report are based on the guidance as written in the 45V NPRM.

4 Except where noted, all estimates in this report result from the optimal project configuration based on the parameters specified (e.g., year, project size, location, technology, and energy resources). As a result, these estimates often appear lower than those made in other reports. This same approach was taken in *Commercial Liftoff: Clean Hydrogen* (March 2023).

5 Except where noted, "low-carbon reformation" refers to hydrogen produced either from steam methane reformation (SMR) or autothermal methane reformation (ATR) with carbon capture and storage (CCS). See Appendix 1 for key terminology and acronyms.

Section 1: Updates to Project Momentum

KEY TAKEAWAYS

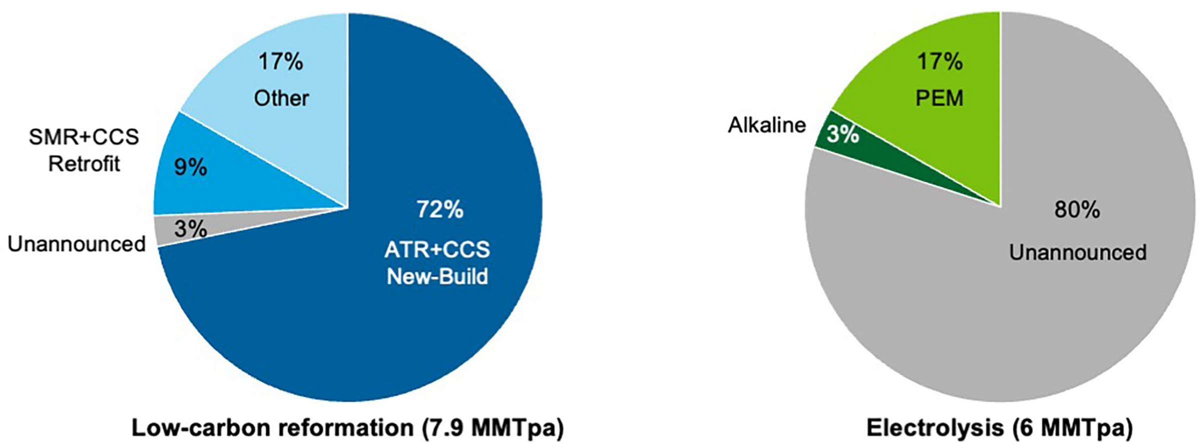
The United States is on track to reach 7-9 MMTpa in operational capacity by 2030. Investment in clean hydrogen has nearly doubled in the last year—not including the approximately $50 billion of capital associated with DOE H2Hubs—shrinking the amount of additional capital investment required to achieve liftoff by 30-60%, to $30-150 billion from the $85-215 billion gap reported in in the 2023 Liftoff report.

Over the last year, total announced production capacity—from projects across the project development funnel—has increased by roughly 26% to 14 MMTpa.[6] In addition, on October 13, 2023, OCED announced seven projects selected for the Regional Clean Hydrogen Hubs Program, which collectively represent another 3 MMTpa of production capacity. The selected H2Hubs, located across the country, include multiple methods of hydrogen production and engage a wide range of hydrogen offtakers and end users. In July 2024, OCED began awarding the H2Hubs to begin work in Phase 1 to solidify planning, development, and design activities.[7]

Analysis of the 14 MMTpa announced production capacity from non-H2Hubs highlights key trends in the developing clean hydrogen ecosystem:

Announced low-carbon reformation projects are dominated by ATR new-build technology, while announced electrolysis projects largely have not announced a selected technology. Of electrolysis projects with a publicly announced technology, most plan to use PEM.

U.S. clean hydrogen production technology selection by announced capacity (excluding H2Hubs), %



Data Sources: McKinsey, Hydrogen Insights Project and Investment Tracker, as of January 2024

Figure 1. Technology selection for U.S. clean hydrogen production by announced capacity. Announced capacity is derived from projects announced as of January 2024.

- **Project design:** 7.9 MMTpa (60% of total announced production capacity) comes from low-carbon reformation projects, 6 MMTpa (40%) comes from electrolysis, and a small and indeterminate amount comes from other pathways, including methane pyrolysis.
- **Technology selection:** Autothermal methane reformation (ATR) new-builds with carbon capture with storage (CCS) and proton exchange membrane (PEM) electrolysis are the most commonly selected pathways within low-carbon reformation and electrolysis projects with announced technologies, respectively.

6 Some third-party sources, like Bloomberg New Energy Finance (BNEF), estimate 10 MMTpa as the total announced production capacity unrelated to H2Hubs. The tracker in this 2024 update includes some projects that may have lower rates of carbon capture (and therefore higher carbon intensities) associated with hydrogen production. DOE has opted to include these projects because many of them, representing 3 MMTpa of capacity, have not completed their Front-End Engineering Design (FEED) studies and have not finalized their respective carbon capture rates. Other discrepancies come from the exclusion of projects announced but currently on hold (0.5 MMTpa). This same approach was taken in *Commercial Liftoff: Clean Hydrogen* (March 2023).

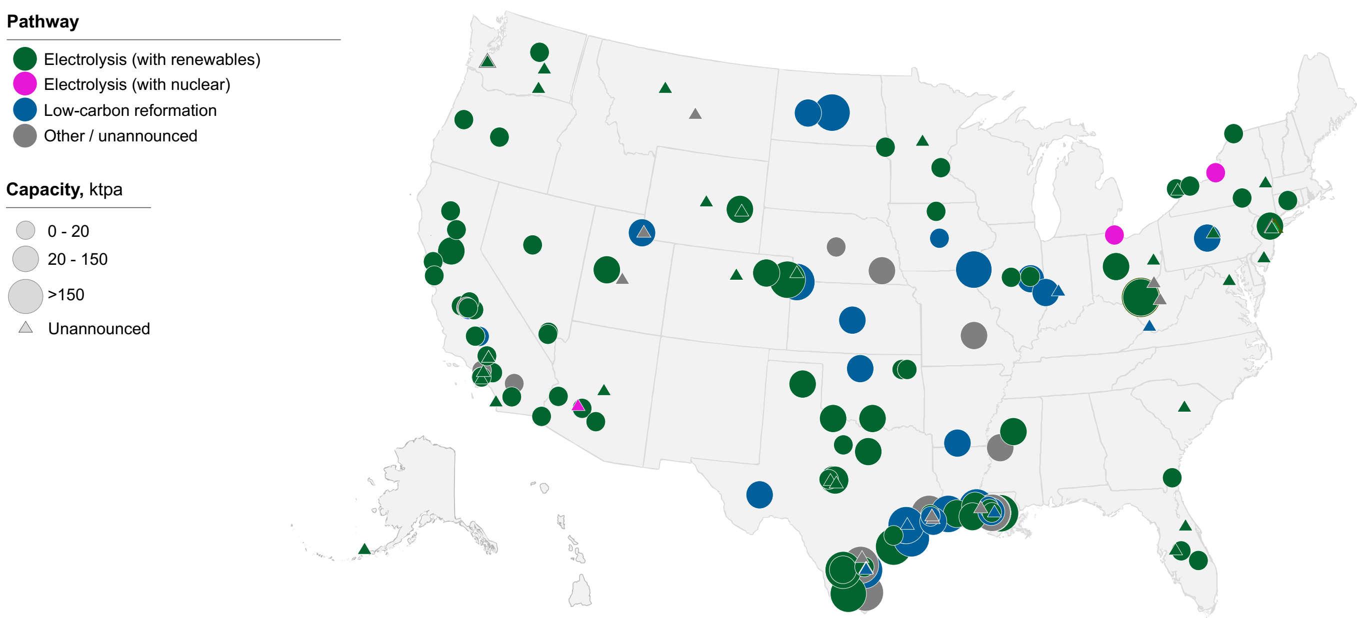
7 The awarded H2Hubs include Appalachian Hydrogen Hub (ARCH2), California Hydrogen Hub (ARCHES), Gulf Coast Hydrogen Hub, Midwest Hydrogen Hub, and Pacific Northwest Hydrogen Hub (PNWH2).

Within the 7.9 MMTpa of low-carbon reformation capacity, ATR new-builds with CCS represent 72% of capacity, steam methane reformation (SMR) retrofits (to incorporate CCS) represent 9% of capacity, and the remaining 19% of capacity has either not been announced or leverages other technologies, like new-build SMR with CCS. Although most electrolytic hydrogen does not have an announced electrolyzer technology, PEM constitutes over 80% of capacity with announced electrolyzer technologies. See Figure 1 for illustration.

- **Clean energy selection:** More than 55% of the 6 MMTpa of announced electrolytic capacity relies on wind, solar, or some combination of the two to power the electrolyzer. Less than 1% of capacity, or 0.5 ktpa, utilizes nuclear power, 0.2 ktpa of which is operational today. The remaining 44% of electrolytic capacity has designated other or to-be-announced energy sources.
- **Geography:** Over the last year, there has been an outsized increase in announced projects in Texas and Louisiana where production costs are relatively cheaper than other regions (see more detail in Section 2). These projects account for almost 75% of total announced production capacity, as illustrated in Figure 2.

Clean hydrogen production projects are planned throughout the U.S., with announced projects in over 30 states.

U.S. announced clean hydrogen production projects[a], as of January 2024



As of January 2024, there is 14 MMTpa of announced clean hydrogen production capacity in the United States

Not including the roughly 3 MMTpa of announced capacity associated with DOE's H2Hubs Selections

Figure Footnotes:

a. The well-to-gate carbon intensity of these projects will depend on their final design and the manner in which they are operated. This map represents projects that are expected to be capable of producing clean hydrogen given the feedstock and/or hydrogen production technology described in their public announcements, in publicly available information, and/or by their developers.

b. About one-third of projects have an assigned state, but not an exact municipality; these projects are indicated as a circle or triangle at or near the center of their respective states.

c. Pennsylvania is in both the Appalachian Hydrogen Hub and the Mid-Atlantic Hydrogen Hub.

Data Sources: McKinsey, Hydrogen Insights Project and Investment Tracker, as of January 2024

Figure 2: Map of announced clean hydrogen production projects as of January 2024. Triangles represent locations of announced clean hydrogen projects, exclusive of H2Hubs, and are colored by production pathway and sized by announced capacity, where available. Where only state-level location is available, circles are placed in the center of the state containing the hydrogen project. Announced projects without at least state-level locations available are not included on the map but their capacities are included in the 14 MMTpa estimate.

Most of the increased project development activity has occurred among early-stage projects. Low-carbon reformation projects make up most of the movement within and across the FEED and FID+ stages.

U.S. project development funnel through 2030[a] (excluding H2Hubs), MMTpa

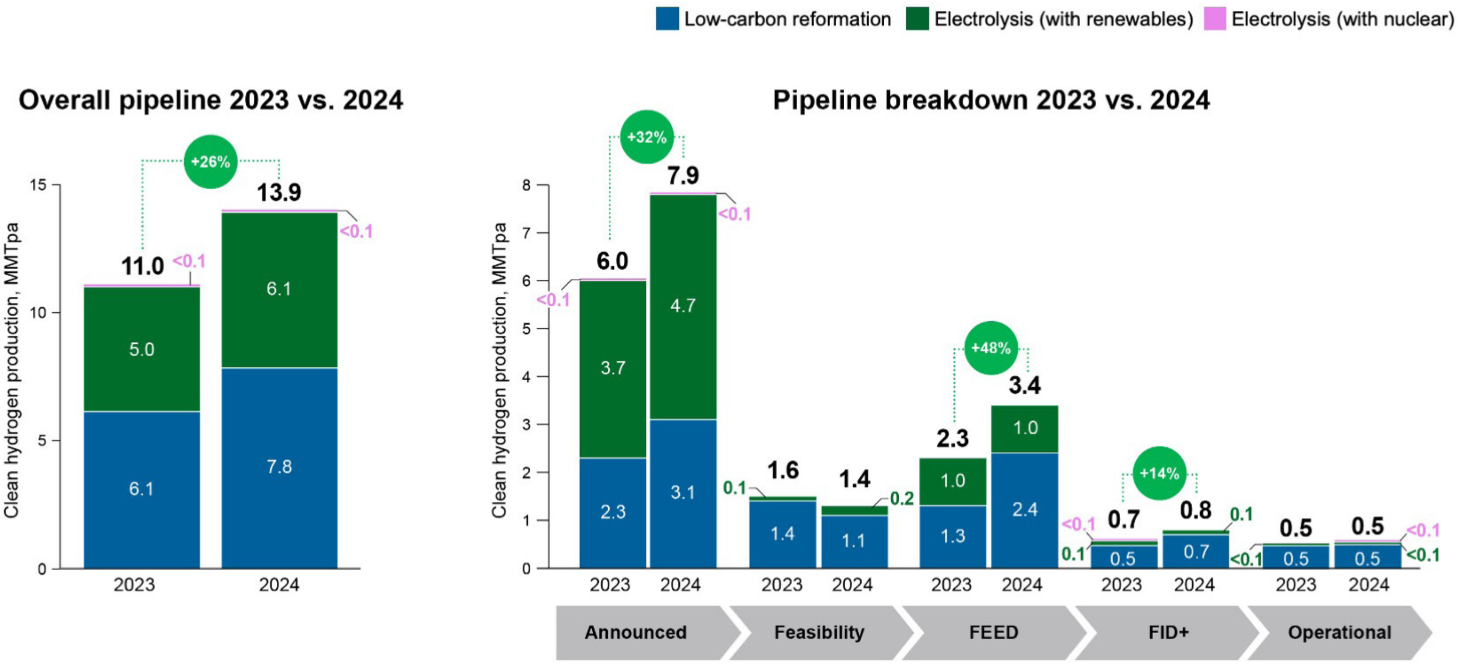


Figure Footnotes:

a. Data is shown as of January of the year listed. Values exclude projects with an announced commercial operation date (COD) post-2030. In *Commercial Liftoff: Clean Hydrogen* (March 2023), projects with an announced COD beyond 2030 were included, resulting in 1MMTpa higher capacity reported. Values exclude capacity associated with DOE's H2Hubs.

Data Sources: McKinsey, Hydrogen Insights Project and Investment Tracker, as of January 2024

Figure 3: Announced clean hydrogen production projects (excluding H2Hubs) by stage in the project development funnel. Bar height indicates hydrogen production capacity (in MMTpa) and the color indicates production pathway.

Most project development activity has occurred earlier in the project development funnel, with comparatively less development in later funnel stages. Figure 3 highlights the year-over-year change in project development according to stage:

- **Announced:** New announcements for both electrolysis and low-carbon reformation projects, representing 1 MMTpa and 0.8 MMTpa, respectively.
- **Feasibility:** No significant change in total capacity of projects entering the Feasibility stage. As some projects have progressed to the FEED stage, newer projects have come into the Feasibility stage.
- **Front-End Engineering Design (FEED):** Nearly 50% uptick in capacity due to several large low-carbon reformation projects progressing into the FEED study phase.
- **FID+/Operational:** No significant movement beyond FEED stage due to increased production costs (see Section 2), pending policy clarity, and lack of offtake and financing agreements.

The lag in projects progressing to FID+ could impact how much capacity will come online by 2030. Despite 17 MMTpa of total announced production volume in the United States, project delays and cancellations may reduce operational production capacity to 7-9 MMTpa (Figure 4).[8] Although this projection is slightly lower than the *U.S. National Clean Hydrogen Strategy and Roadmap* target of 10 MMTpa of operational production capacity by 2030, it conservatively assumes no new project announcements in 2024 and 2025 that could reasonably come online by 2030.

Based on typical project timelines and success rates, operational clean hydrogen capacity could reach 7-9 MMTpa by 2030.

U.S. project development funnel through 2030[a] (excluding H2Hubs), MMTpa

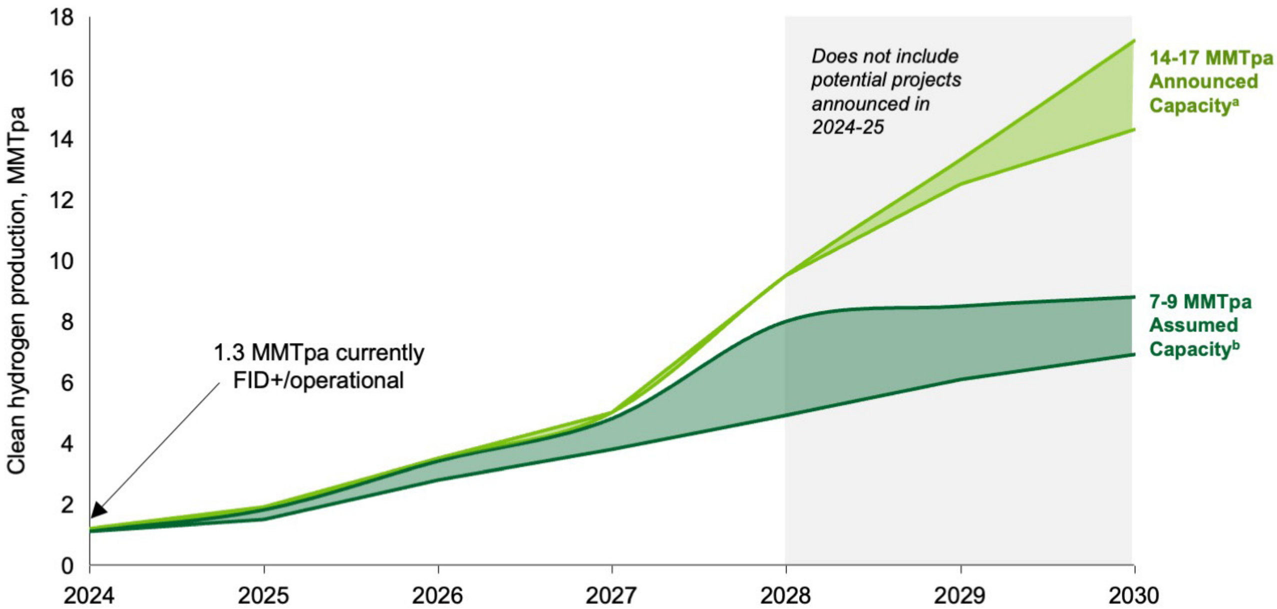


Figure Footnotes:

a. Range includes the announced capacity from all announced clean hydrogen production projects expected to come online by 2030. Low end of the range excludes DOE's H2Hubs (which do not have an announced COD).

b. Range includes the operational capacity projected to come online by 2030. High end of range includes all projects with a publicly announced COD by 2030; low end of range applies a project timeline and attrition rate to the total announced capacity, including H2Hubs (17 MMTpa). This timeline and attrition rate are based on analogous offshore wind projects, with adjustments based on expert interviews. See Appendix 2 for methodology.

Data Sources: McKinsey, Hydrogen Insights Project and Investment Tracker, as of January 2024

Figure 4: Expected hydrogen production in MMTpa, based on currently announced projects, from 2024 to 2030.

Reaching 10 MMTpa of operational production capacity by 2030 will require $120-240 billion of cumulative capital to scale hydrogen production and the requisite clean energy generation, distribution and storage infrastructure, and offtake (Figure 5).[9] This projection is a slight uptick—largely due to inflation—from *Commercial Liftoff: Clean Hydrogen* (March 2023) which stated that $105-235 billion of cumulative investment was needed.

Despite the uptick in total investment required, the investment gap to reach the 2030 target has shrunk significantly since March 2023, from $85-215 billion to $30-150 billion. Anticipated investments (dollars planned, committed, or distributed to projects) have doubled to $42 billion. DOE's H2Hubs represent an additional $50 billion of investment—$8 billion of DOE funding plus an additional $40 billion or more of private-sector crowd-in.

8 Project risk-weighting methodology is based on similar development timelines and attrition rates in other emerging clean energy technologies like offshore wind, with additional input from hydrogen developers. See Appendix 2 for full methodology.

9 See Appendix 3 for methodology.

Year-over-year anticipated investment across the clean value chain doubled. DOE's H2Hubs could make up another $50 billion investment, with $8 billion from DOE and potentially over $40 billion of private sector co-investment.

Investments into U.S. clean hydrogen value chain, $Billion

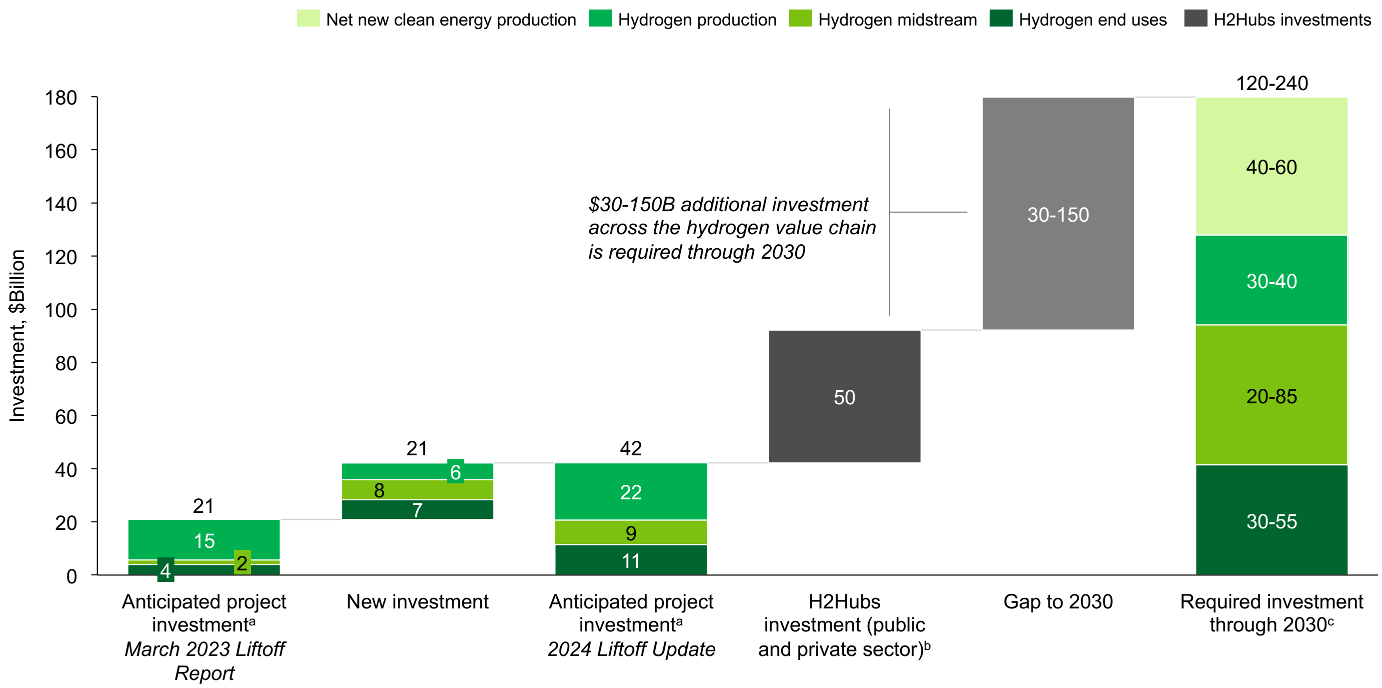


Figure Footnotes:

a. Represents total planned investments for projects in the development funnel based on most recent public information, excluding pre-feasibility study production projects. This same methodology and selection criteria were used in *Commercial Liftoff: Clean Hydrogen* (March 2023).

b. DOE estimates $8B for H2Hubs and over $40B of private sector crowd-in.

c. Calculated based on current cost information used in this 2024 report update, assuming reformation (56%) / electrolysis (44%) split from McKinsey Hydrogen Insights Project and Investment tracker. Required investment increased modestly compared to *Commercial Liftoff: Clean Hydrogen* (March 2023) – $105-235B previously v. $120-240B in this 2024 report update.

Data Sources: McKinsey, Hydrogen Insights Investment Model; McKinsey, Hydrogen Insights Project and Investment Tracker, as of January 2024

Figure 5: Anticipated investment in the hydrogen value chain required to reach the *U.S. National Clean Hydrogen Strategy and Roadmap* target of 10 MMTpa of operational hydrogen production capacity by 2030. Bar height indicates investments in billion 2022$. The 2030 required investment range is based on the Net Zero 2050 scenario, pulling demand from the *U.S. National Clean Hydrogen Strategy and Roadmap*, the *U.S. Long-Term Strategy*, and McKinsey's Hydrogen Technology Spike Case, which assumes that clean hydrogen technologies advance more quickly than other decarbonization technologies,[10] causing increased demand from across all end uses.

10 "Other decarbonization technologies" include long-duration energy storage, advanced nuclear power, and carbon management solutions.

Section 2: Updates to Estimated Production Costs

KEY TAKEAWAYS

Estimated production costs for clean hydrogen have increased since March 2023, with disproportionately larger increases for electrolysis than for low-carbon reformation. That said, cost reductions are expected for both pathways over the next few years. Furthermore, policies like the 45V production tax credit can help accelerate the timeline to make clean hydrogen competitive with unabated fossil-based alternatives. At the time of this analysis, 45V final rulemaking is underway. Except where noted, this report's tax credit analyses are based on the guidance as written in the 45V NPRM (December 2023).

Today, carbon-intensive reformation represents 95% of hydrogen production in the United States. This pathway typically produces 9-11 kg CO_2e/kg H_2, whereas the June 2023 *U.S. National Clean Hydrogen Strategy and Roadmap* defines clean hydrogen as resulting in an emissions rate of less than 4 kg CO_2e/kg H_2, which is also the maximum allowable emissions rate to qualify for the 45V tax credit.[11] Clean hydrogen has historically been more expensive to produce than unabated fossil-based alternatives, given the relative nascence of technologies involved, the more complex design requirements, and, for some pathways, the more expensive feedstocks. Clean hydrogen production costs have also increased more relative to traditional hydrogen production costs in the last year. However, tax credits like 45V or 45Q close this gap for some clean hydrogen today and shrink it for others.[12]

11 See Footnote 1.

12 Developers cannot claim both 45V and 45Q tax credits. Proposed section 45V(d)(2) stipulates that no facility can qualify for both 45V and 45Q for the taxable year or any prior taxable year.

Low-carbon reformation and electrolysis powered by clean sources have some of the greatest potential for lowering the carbon intensity of hydrogen production, but cost reductions are needed, particularly for electrolysis.

Comparison of hydrogen production pathways in the U.S.

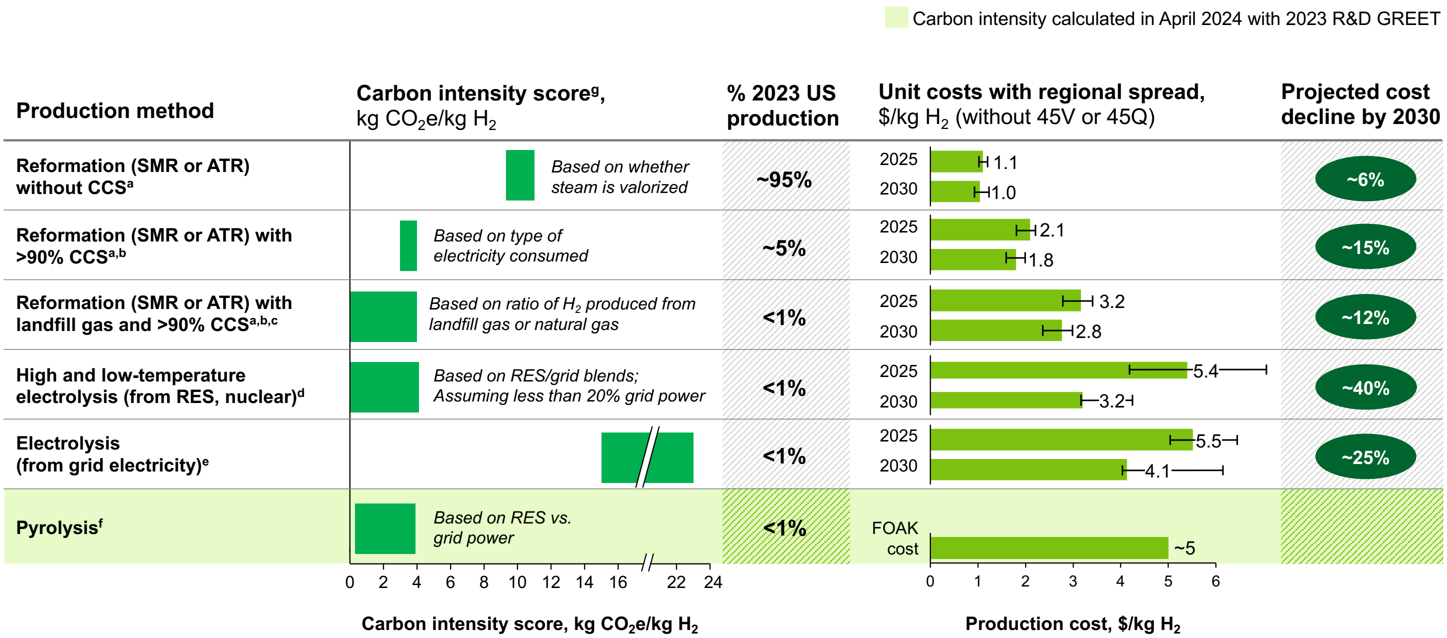


Figure Footnotes:

a. Costs shown for SMR facility with no CCS. Assume facility capex (480 TPD) $360M (2025 and 2030). Range based on Energy Information Administration (EIA) high oil price and low oil price scenarios for California and Texas; midpoint represents EIA national base case gas prices. The corresponding industrial electricity price base case was used. Carbon intensity (CI) calculated for SMR without CCS with range based on high (Texas) and low (California) grid intensities.

b. Costs shown for ATR and SMR facilities with CCS on all emissions sources. Assume ATR facility capex (660 TPD) $1.1B (2025 and 2030). SMR facility capex (480 TPD) $600M (2025 and 2030). High end of CI score range assumes use of grid electricity and low end assumes up to 90% of clean power–the lowest percentage permittable to achieve a CI score that qualifies for 45V. See Figure 9 for more cost information.

c. Assumes landfill gas, one form of renewable natural gas (RNG), priced at $15/MMBtu (based on studies conducted by the American Gas Foundation and supplemented with stakeholder interviews) in ATR or SMR facility with CCS. Under the final rules for 45V, H_2 produced with 100% RNG with CCS (with a 90% capture rate) could result in a near-zero or negative CI score; that facility-wide CI score of all H_2 produced (including that from RNG and natural gas) may exceed 0. The final rules also disallow CI scores calculated from H_2 produced from blends of RNG and natural gas; CI scores must be calculated independently based on their unblended feedstock stream. The CI range in the figure represents a facility-wide CI score with between 47-100% of H_2 produced from landfill gas.

d. CI dependent on grid intensity; <4 kg CO_2e/ kg H_2 can be achieved in several Natural Environment Research Council (NERC) regions in the United States (e.g., WECC, NPCC) by blending 5-20% grid power with low-emission renewable energy sources (RES) to achieve 0.45 kg CO_2e/kg H_2 or 4 kg CO_2e/kg H_2 (the CI cutoffs for the highest and lowest value tiers of 45V), respectively. Midpoint costs are shown for West Texas electrolysis scenario, high case is from Southern California scenario, and low case is from Illinois nuclear scenario. See Figure 8 for more cost information.

e. CI score range using 100% grid power from California (low) and Texas (high); 100% grid power in average CI grid would assume 24.4 kg CO_2e/kg H_2. Costs shown use the U.S. average grid power price as well as a high (California) and low (Texas) case. See Figure 8 for more cost information.

f. CI score is based on preliminary estimates from 2023 R&D GREET, which vary depending on the method of co-product accounting used and the type of electricity consumed. CI range is based on using either full grid power or 100% qualifying low emission power. Costs are shown based on Kerscher, Florian, et al., current interest rates, and updated Lang factor.

g. CI scores are derived using 45VH2-GREET as of April 2024 for all pathways currently represented in the model. For upstream methane emissions, default GREET values are used, which are consistent across 2023 R&D GREET and 45VH2-GREET. For the production methods that can qualify for 45V, only scenarios that yield CI scores below 4 kg CO_2e/ kg H_2 are presented since 45V is a crucial driver to commercial liftoff for these pathways. Some of these pathways may have scenarios in which the CI score is higher than 4 kg CO_2e/ kg H_2 (e.g., the electrolysis pathway powered by more than 20% grid power).

Data Sources: American Gas Foundation, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment (December 2019); Argonne National Laboratory (ANL), 45VH2-GREET and R&D GREET Models as of April 2024; EIA, *Annual Energy Outlook* (2023); Florian Kerscher, et al., "Low-Carbon Hydrogen Production via Electron Beam Plasma Methane Pyrolysis: Techno-Economic Analysis and Carbon Footprint Assessment," International Journal of Hydrogen Energy 46, no. 38 (2021): 19897–19912; Hydrogen Council, *Hydrogen for Net-Zero: A Critical Cost-Competitive Energy Vector* (November 2021); LevelTen, *PPA Index*, as of December 2023; NREL, *Annual Technology Baseline* (2023); DOE, *Clean Hydrogen Production Cost Scenarios with PEM Electrolyzer Technology* (2024)

Figure 7: Comparison of domestic hydrogen production pathways in the U.S. carbon intensity (CI) scores, percent 2023 U.S. production, current production cost estimates, and projected cost declines by 2030. CI scores are indicated in green boxes with box length representing the range in possible values in kg CO_2e/kg H_2. Costs are estimated without 45V or 45Q tax credits for both 2025 and 2030 with projected cost declines provided in green circles on the right edge of the figure. Cost ranges indicate regional differences.

DOE's estimates of electrolytic hydrogen production cost have increased by $2-3/kg since March 2023. Several factors contribute to this increase. First, as more electrolysis projects begin development, industry has increased its electrolyzer capex estimates to account for higher installation costs (see Figure 9 for more detail). Second, rising interest rates have increased the cost of capital, bringing the weighted average cost of capital (WACC) to more than 10%. Third, developers are incentivized to capture the full value of the 45V PTC, which necessitate meeting the hourly time-matching and incrementality requirements, as described in the December 2023 45V NPRM.[13] Finally, power purchase agreement (PPA) prices have risen in recent years—between Q2 2020 and Q2 2023, national solar and onshore wind PPA prices have increased by 55% and 63%, respectively. Figure 8 illustrates how these factors impact overall cost estimates for an example electrolysis project based in West Texas that has an optimized ratio of solar, wind, and electrolyzer capacities.

An illustrative 500 MW PEM facility based in West Texas breaks out the $2-3/kg increase in production cost estimates from March 2023 to January 2024. This increase includes the effects of meeting the eligibility requirements for the highest tier ($3/kg) of the 45V tax credit as defined in the December 2023 45V NPRM, and the illustrative decrease includes the levelized value of the full credit.

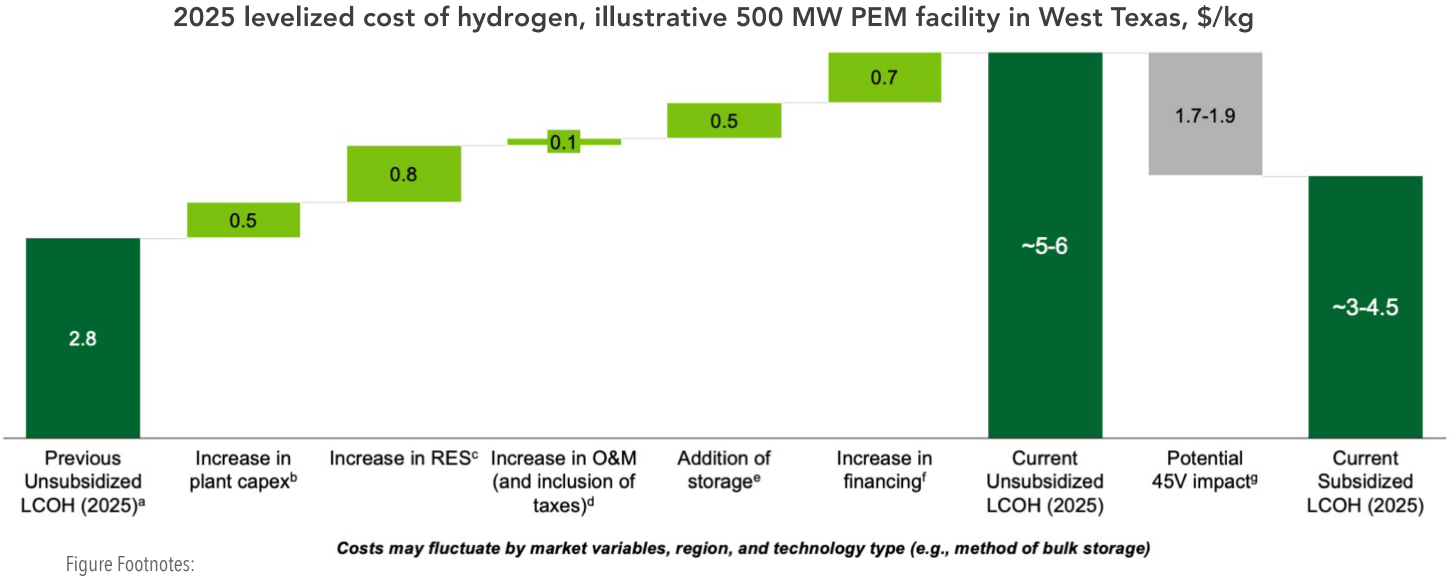


Figure Footnotes:

a. Class 1 Wind PEM facility used as a proxy, see *Commercial Liftoff: Clean Hydrogen* (March 2023) and include adjustments for inflation. Assumes roughly 14% inflation between 2020$ and 2022$, based on Bureau of Economic Analysis Gross Domestic Product (GDP) Implicit Price Deflator calculator. This hypothetical project would not meet the lifecycle emissions requirements as described in the December 2023 45V NPRM.

b. Assumes $1,850 /kW plant capex for a 500 MW project size with estimated 20 MW system size using PEM electrolyzers. Plant capex has increased from $1,400-1,600/kW from *Commercial Liftoff: Clean Hydrogen* (March 2023) primarily due to increased installation costs (see Figure 8 for more detail).

c. Large portion of cost increase is RES due to cost optimal strategy of overbuilding RES to maximize electrolyzer utilization and meet the hourly time matching requirements needed to qualify for the 45V tax credit as described in the December 2023 NRPM. Applies an optimal build mix of 1.0-to-1.4-to-1.0 solar-to-wind-to-electrolyzer ratio, 23% solar and 39% wind capacity factor. Uses wind power co-located with electrolysis ($36/MWh), plus solar sourced through a virtual power purchase agreement (VPPA) in ERCOT ($58/MWh, inclusive of transmission and delivery); electricity costs include excess power sold back to the grid (<$0.2/kg value), assuming power can be sold at $20/MWh from ERCOT typical real-time market prices during times of peak RES generation.

d. Modest increase in costs due to incorporation of levelized tax value (25.74% total state and federal income tax rate assumed in NREL H2A-Lite model).

e. Addition of H_2 storage to meet end use demand; assumed salt cavern storage (roughly $40/kg stored capex). Cost increases are inclusive of compression and pipeline expenses. Assumes 95% firm H_2. Assumes 3-day storage with 40% cushion gas, including low utilization (22-23%) 200-mile 14-inch pipeline that is sized for a maximum flow rate of 10 tons per hour, which equates to transport and storage for the full 500 MW hourly capacity.

f. Near-term WACC assumption was increased to 10% based on recent increases in interest rates.

g. Assumes project qualifies for the highest tier of 45V at $3/kg. Assumes that the project lifetime is 25 years, resulting in a levelized tax credit value of $1.7-1.9/kg due to the fact that the tax credit expires after 10 years.

Data Sources: ANL, Hydrogen Delivery Scenario Analysis Model (HDSAM), as of February 2024; DOE, *Commercial Liftoff: Clean Hydrogen* (March 2023); LevelTen, *PPA Index*, as of December 2023; McKinsey Energy Solutions, H2 Cost Optimization Model (H2–COM); NREL, H2A-Lite Model, as of February 2024

Figure 8: Levelized cost of hydrogen (LCOH) estimate increase for an illustrative 500 MW PEM facility in West Texas in 2025. Leftmost and rightmost bars in dark green show estimated LCOH from *Commercial Liftoff: Clean Hydrogen* (March 2023) and this 2024 report update, respectively. Bars in between in light green and gray illustrate contributions to the current higher estimated LCOH by cost category.

13 Given that the *Commercial Liftoff: Clean Hydrogen* (March 2023) was published prior to the 45V NPRM, for simplicity, it was assumed that all hydrogen produced via electrolysis would be eligible for the full value of the credit and could purchase unbundled clean electricity credits from existing clean sources. Final 45V rules also include electrolytic pathways that could result in different cost profiles, including the use of existing nuclear power that meets the incrementality requirement.

As Figure 9 illustrates, total installed electrolyzer capex estimates, blended for both PEM and alkaline electrolyzers, have increased from $1,400-1,600/kW last year to $2,100/kW. Most of the cost increases derive from higher installation costs due to inflationary pressures and other unforeseen costs during implementation.[14] Unless otherwise noted, this 2024 report update leverages the average PEM installation capex ($1,850/kW).[15]

Total installed electrolyzer capex estimates have increased by roughly 30%, primarily due to higher installation costs.

U.S. electrolyzer capex estimates[a], $/kW

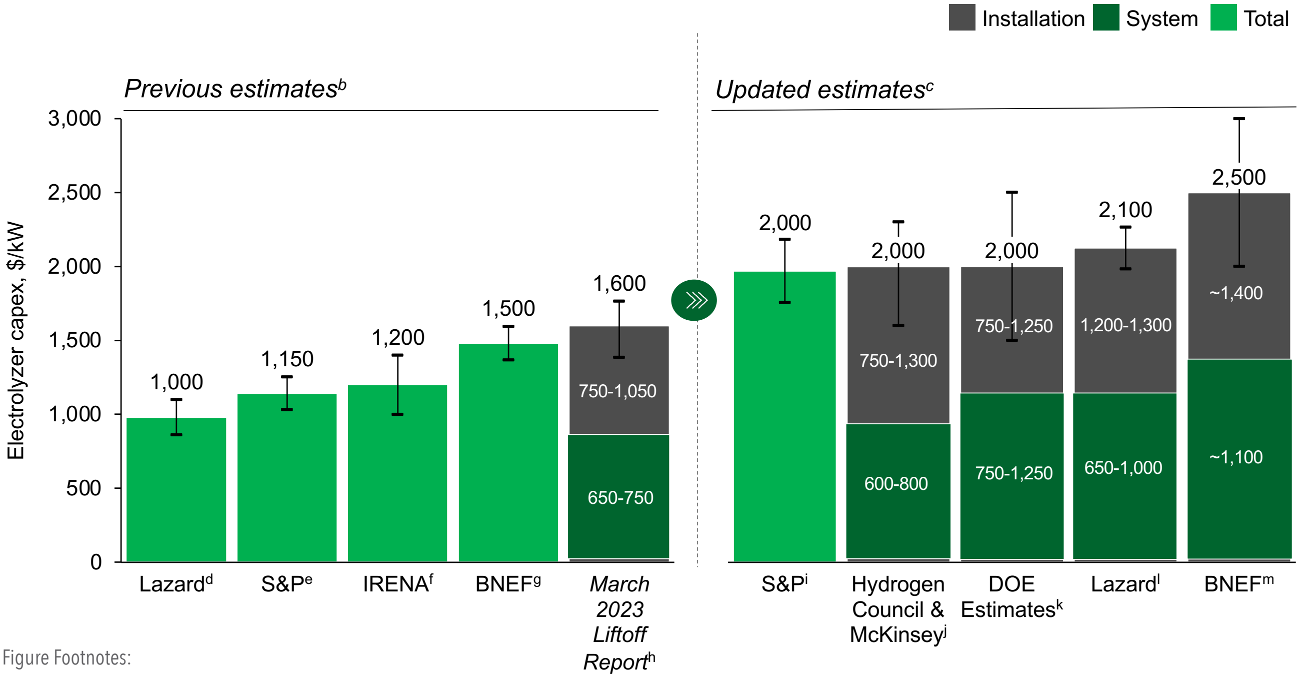


Figure Footnotes:

a. Installation costs include labor costs, piping, transportation costs, permitting, contingency, EPC, and all other expenses incurred to bring the system to a condition where it can be used. DOE Estimates (2024) and BNEF (2024) numbers include equipment costs associated with balance of plant (water treatment, management, etc.) in system costs, while others include these costs in installation costs. The capitalization treatment of these installation and system costs should be governed by generally accepted accounting principles (GAAP) or other widely accepted accounting standards.

b. Range based on alkaline and PEM estimated costs, unless otherwise noted. Note the references shown were published in different years and inflation may have influenced cost fluctuations within those years. The costs shown in this figure have not been adjusted for a consistent dollar year because of uncertainty regarding the impacts of inflation within those years.

c. Unless otherwise noted, range is based on blended alkaline and PEM estimated costs and 2022$.

d. 20 MW project size, 2021$.

e. 100 MW project size, mean of 2020 and 2025 estimated costs used, 2021$.

f. >10 MW project size, 2020$.

g. >10 MW project size, 2022$.

h. 2 MW electrolyzer size, assuming no economies of scale with project size, 2020$.

i. 100 MW project size, 2021$.

j. 1 GW project size, range based on spread in survey responses and uncertainty in engineering analysis.

k. Based on industry estimates, assuming an average 300 MW project size, PEM only.

l. 20 MW project size.

m. 100 MW project size. Similar to DOE estimates, balance of plant costs are included in system costs.

Data Sources: BNEF, "2023 Hydrogen Levelized Cost Update: Green Beats Gray" (2023); BNEF, "Electrolyzer Price Survey 2024: Rising Costs, Glitchy Tech" (2024); DOE, *Commercial Liftoff: Clean Hydrogen* (March 2023); DOE, *Clean Hydrogen Production Cost Scenarios with PEM Electrolyzer Technology* (2024); International Renewable Energy Agency (IRENA), "Green Hydrogen Cost Reduction: Scaling Up Electrolyzers to Meet the 1.5C Climate Goal" (2020); Lazard, "Levelized Cost of Hydrogen Analysis – Version 2.0" (2021); Lazard, "Levelized Cost of Hydrogen Analysis – Version 3.0" (2023); McKinsey Capital Analytics, "Survey of Hydrogen Council Member FEED Studies" (2023); S&P, "Economics of Low-Carbon Hydrogen End Use in Industry — V2.4" (2023); S&P Global Commodity Insights, "Rising Costs: The Economics of Hydrogen Production" (2024)

Figure 9: Previous (left) and updated (right) electrolyzer capex estimates n $/kW in the United States. Where available, costs are broken down into installation and system costs in gray and dark green, respectively.

14 DOE estimates and BNEF 2024 numbers include balance of plant costs in system costs, resulting in system cost increases appearing greater.

15 Weighted average cost estimates for PEM and alkaline electrolyzers are similar. However, proposed project sizes are typically bigger for PEM projects (over 400 MW) than for alkaline projects (200-300 MW). Therefore, this report includes a lower PEM electrolyzer capex estimate ($1,850/kW) than the blended electrolyzer capex estimate ($2,000/kW) due to assumed economies of scale.

Despite expected increases in 2025 costs over the last year, electrolytic hydrogen production costs could decline by $1-4/kg between 2025 and 2050 (Figure 10). These cost reductions are primarily due to declines in electrolyzer capex, lower interest rates, and falling renewables costs. Total costs and reductions in cost vary by U.S. region. The main driver of cost differences across the country is the regional variation in RES; however, regional differences in storage capacities and utilization options also play a role.[16] For example, a 500 MW PEM project with co-located wind and virtually procured solar power will have lower levelized production costs if located in West Texas (with access to nearby high capacity wind and solar resources and high capacity solar resources) compared to New Jersey (an area with fewer renewable resources).[17] New Jersey might see renewable energy costs decline more over the next 25 years as levelized costs of energy (LCOE) decrease, potentially shrinking the delta. The selection of clean firm power feedstocks, like existing nuclear power, might also result in lower levelized production costs. These estimates and those in Figure 10 do not include the impacts of 45V.

16 West Texas, Southern California, New Jersey, and Illinois were selected to represent the differences in production costs associated with geography, including but not limited to available renewable (or clean) energy resource capacities and related prices, natural gas prices, and distances to storage facilities. See Appendix 4 for more details on build mix scenarios.

17 West Texas could have a hybrid wind/solar levelized cost of energy (LCOE) of $49.64/MWh and capacity factor of 68% in 2025. By contrast, a similarly designed project based in New Jersey could have a near-term LCOE of $76.12/MWh and capacity factor of 60% in 2025.

Near-term cost estimates exceed $4/kg across all regions, although regions with high quality solar, wind, and nuclear power sources have an advantage due to relatively lower feedstock costs. By 2050, levelized costs may decrease to $2.4-3.3/kg across all regions.

Projected LCOH for PEM electrolysis across regions (excluding 45V)[a], $/kg

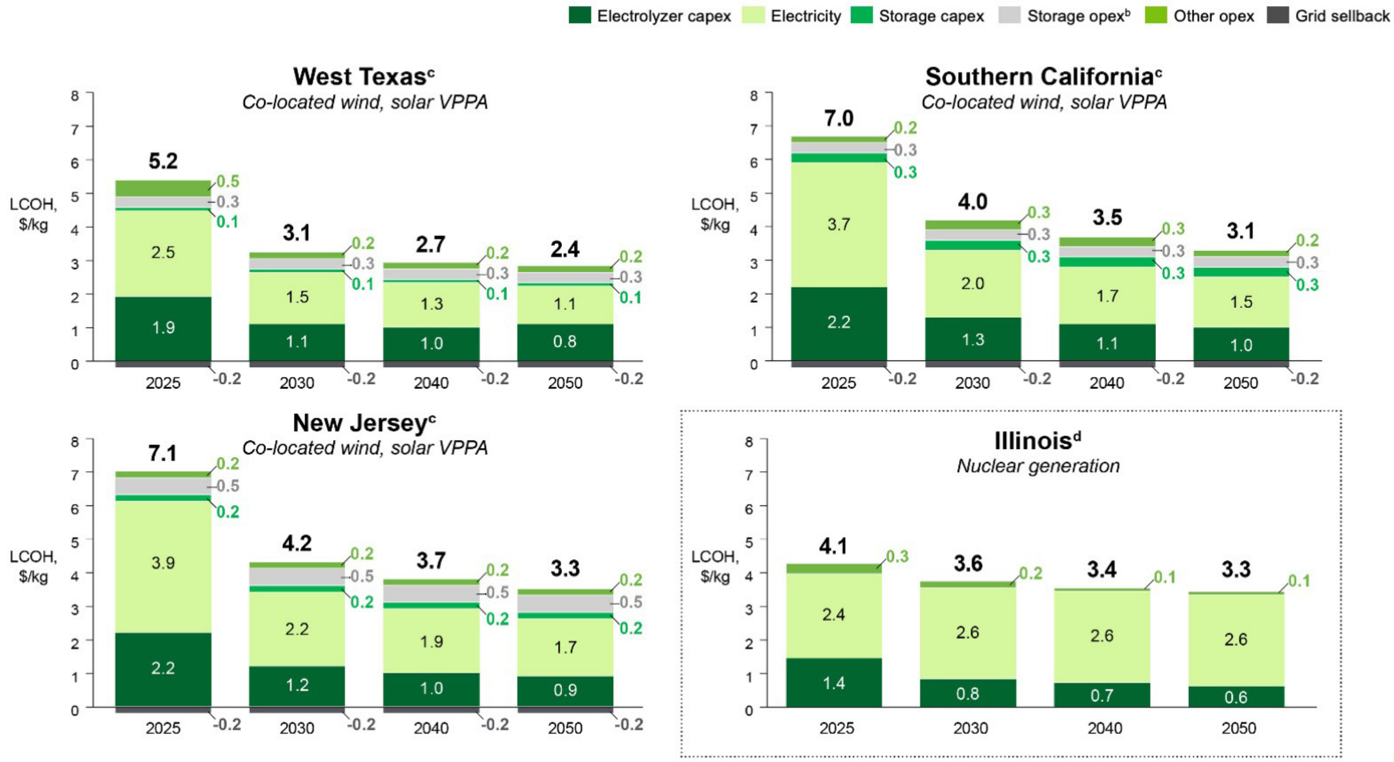


Figure Footnotes:

a. Assumes 500 MW PEM facility with salt cavern storage (including compression). Electrolyzer efficiency of 66% (2025), 68% (2030), 69% (2040), and 70% (2050). Assumes 25-year asset lifetime, with electrolyzer depreciation over 20 years. Assumes WACC of 10% (pre-2030) and 7% (2030 onwards).

b. Storage opex includes pipeline transport to nearest storage facility. See Appendix 4 for more detail on build mix assumptions.

c. LevelTen *PPA Index* prices used for 2025, NREL *ATB* resource classification assigned to geography used for 2030 onward. "Co-located wind, solar VPPA" indicates that the electrolyzer is sited adjacent to the wind farm and does not need to pay transmission and distribution (T&D) costs, while solar is sourced through a VPPA, including T&D costs; the reverse is true for "co-located solar, wind VPPA."

d. PJM power price futures from S&P used as proxy. Electrolyzer capex is lower in the Illinois case compared to the other regions because the electrolyzer capacity factor is higher with nuclear (95%) than with RES (60-70%), thus producing more hydrogen for a given system size (500 MW) and resulting in a lower $/kg levelized cost.

Data Sources: ANL, Hydrogen Delivery Scenario Analysis Model (HDSAM), as of February 2024; LevelTen, *PPA Index*, as of December 2023; McKinsey Energy Solutions, H2 Cost Optimization Model (H2-COM); McKinsey Hydrogen Insights, as of February 2024; NREL, *Annual Technology Baseline* (2023); NREL, H2A-Lite Model, as of February 2024; S&P CapitalIQ; DOE, *Clean Hydrogen Production Cost Scenarios with PEM Electrolyzer Technology* (2024)

Figure 10: Levelized cost of hydrogen (LCOH) in $/kg for PEM electrolysis in four U.S. regions. Bar heights indicate LCOH in each region for 2025, 2030, 2040, and 2050, and the colors of the bars indicate cost categories contributing to the LCOH.[18] See more detailed methodology in Appendix 4.

Low-carbon reformation-based hydrogen is currently and projected to remain cheaper than electrolysis through the 2030s (Figure 11). Costs for low-carbon reformation-based hydrogen have remained relatively stable since the March 2023 report, increasing by only $0.5/kg due to increases in installation, electricity, and financing costs. There have been additional costs and challenges surrounding the availability of carbon sequestration infrastructure in the United States. The change in natural gas prices from the March 2023 report to this 2024 report update is negligible when adjusting for inflation. There is some—but significantly less—regional variability for reformation projects compared to electrolysis, as their feedstocks are less dependent on geography. Declines in feedstock and financing costs will drive down plant capex costs through 2050.

18 Electricity costs for 2025-2029 reflect actual virtual power purchase agreement (VPPA) prices on the market that are both pre-negotiation and not inclusive of buffering for peaking capacity. LCOEs for 2030 onwards pull LCOEs from NREL's *Annual Technology Baseline* (2023), which models electricity costs. As such, the decrease in electricity costs between 2025 and 2030 may appear larger.

Figure 11 represents ATR+CCS new-build projects only, given that most of the low-carbon reformation announced capacity comes from ATR+CCS new-builds (compared to SMR+CCS new-builds or retrofits). ATR+CCS new-build projects typically have higher LCOH than SMR+CCS new-build projects given higher electricity requirements. However, the higher concentration and scale of flue gas stream in ATR makes CCS more efficient, and the 45Q credit could reduce costs by $0.53/kg.[19] Developers could implement additional decarbonization levers to potentially claim up to the full 45V credit, which would likely lead them to forgo 45Q.[20]

Projected low-carbon reformation-based hydrogen production costs are expected to decline from $1.8-2.2/kg near-term to $1.5-2.0/kg long-term.

Projected LCOH for ATR+CCS across regions (excluding 45Q and 45V)[a], $/kg

Figure Footnotes:

a. ATR+CCS assumptions: Assumes 660 tons per day production capacity, operating at 90% utilization with a 94.5% capture rate with a 40-year plant life. Assumes plant+CCS capex of $990M with a WACC of 10% (pre-2030) and 7% (2030 onwards). Plant capex increases in all scenarios in the later years as net financing costs increase (even with a constant WACC) due to increases in dividend payouts. Uses EIA *Annual Energy Outlook* reference case regional industrial gas price and industrial electricity price forecasts for each year of operation. Assumes $22/t CO_2 transport and storage costs, based on the NETL report.

b. Gas price assumptions: $4.5/MMBtu (2025), $3.8/MMBtu (2030), $4.7/MMBtu (2040), $4.5/MMBtu (2050). Electricity price assumptions: $73/MWh (2025), $64/MWh (2030), $68/MWh (2040), $64/MWh (2050). Each levelized production cost uses the next 25 years of gas and electricity price forecasts and assumes prices remain constant post-2050 when forecast ends.

c. Gas price assumptions: $5.7/MMBtu (2025), $4.9/MMBtu (2030), $5.9/MMBtu (2040), $5.8/MMBtu (2050). Electricity price assumptions: $133/MWh (2025), $126/MWh (2030), $130/MWh (2040), $132/MWh (2050). Each levelized production cost uses the next 25 years of gas and electricity price forecasts and assumes prices remain constant post-2050 when forecast ends.

d. Gas price assumptions: $5.0/MMBtu (2025), $4.3/MMBtu (2030), $4.9/MMBtu (2040), $4.6/MMBtu (2050). Electricity price assumptions: $72/MWh (2025), $62/MWh (2030), $61/MWh (2040), $61/MWh (2050). Each levelized production cost uses the next 25 years of gas and electricity price forecasts and assumes prices remain constant post-2050 when forecast ends.

e. Gas price assumptions: $5.6/MMBtu (2025), $4.6/MMBtu (2030), $5.1/MMBtu (2040), $4.9/MMBtu (2050). Electricity price assumptions: $91/MWh (2025), $83/MWh (2030), $85/MWh (2040), $79/MWh (2050). Each levelized production cost uses the next 25 years of gas and electricity price forecasts and assumes prices remain constant post-2050 when forecast ends.

Data Sources: EIA, *Annual Energy Outlook* (2023); NETL, "Fossil-Based Hydrogen Production Comparison" (April 2022); NREL, H2A-Lite Model, as of February 2024

Figure 11: Levelized cost of hydrogen (LCOH) in $/kg for ATR+CCS in four U.S. regions.[21] Bar heights indicate LCOH in each region for 2025, 2030, 2040, and 2050, and the colors of the bars indicate cost categories contributing to the LCOH. See more detailed methodology in Appendix 4.

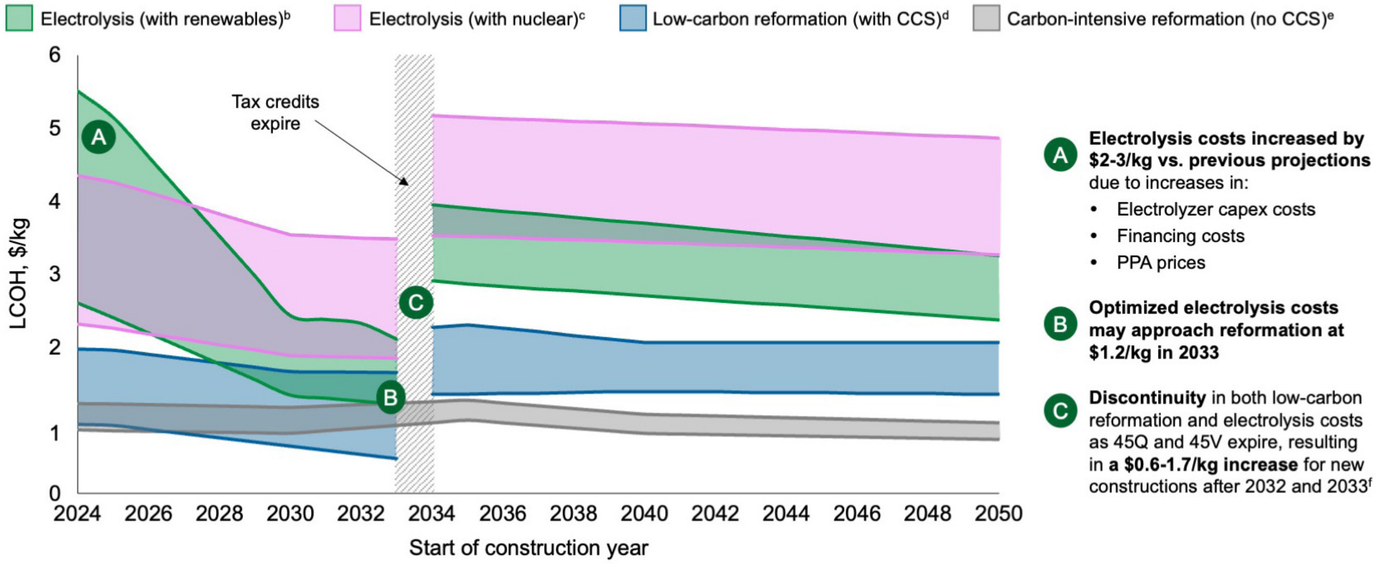
19 The levelized value of $0.53/kg in 45Q tax credit value assumes an ATR+CCS project that produces 660 tons per day and has a 25-year project life.

20 Except where noted in this report, low-carbon reformation projects leverage 45Q (and not 45V) tax credits.

21 For most direct cost comparison, the same four regions were analyzed for low-carbon reformation as for electrolysis.

Tax credits like 45V and 45Q will lower the cost of clean hydrogen compared with its fossil-based alternative (reformation with no CCS); however, despite the meaningful impact of 45V, electrolysis will likely remain more expensive than low-carbon reformation.[22]

Levelized production cost estimates (including value of 45V and 45Q credits)[a], $/kg



a. All projects: 45V credit values are estimated according to the 45V NPRM released in December 2023 and assume a 10-year expiry. Assumes that an existing nuclear plant can be uprated to meet the incrementality requirements as laid out in the 45V NPRM to qualify for the full $3/kg 45V PTC (see Footnote C for more detail). 45Q credit values assume expiry in 2032. All projects assume a WACC of 10% (pre-2030) and 7% (2030 onwards). Assumes tax credits are not extended beyond 2032 (45Q) and 2033 (45V).

b. 500 MW PEM electrolyzer project with a 25-year project life and 20-year electrolyzer depreciation period, using the same optimized build mix of solar, wind, electrolyzer utilization, compression, transport, and geologic storage shown in Figure 9. The spread in values accounts for regional differences with high estimated production costs in New Jersey and California, and low estimated production costs in Texas. Uses LevelTen *PPA Index* prices through 2025, and NREL *ATB* resource classification for 2030 onward.

c. Electrolysis powered by nuclear: Shows the production costs for a 500 MW PEM electrolyzer projects with a 25-year project life, using the same optimized compression, transport, and geologic storage shown in Figure 9. Low end of range assumes LCOE for an existing nuclear plant that was uprated to meet the incrementality requirements as laid out in the 45V NPRM. This LCOE uses PJM power price futures from S&P as a proxy. High end of range assumes LCOE from a new-build nuclear facility. This LCOE uses the NREL *ATB* resource classification. Note that estimates for both the high and low case for nuclear and assume up to $3/kg 45V PTC.

d. Low-carbon reformation: Assumes 660 tons per day production capacity, operating at 90% utilization with a 94.5% capture rate with a 40-year plant life. Assumes plant+CCS capex of $990M. Assumes $22/t CO_2 transport and storage costs, based on the NETL report. The spread in values is also due to the range in high and low oil price scenarios, using EIA *Annual Energy Outlook* reference case regional industrial gas price and industrial electricity price forecasts for each year of operation. The additional spread in values is also due to blending production costs not only for ATR+CCS new-builds (as in Figure 10) but also SMR+CCS new-builds and retrofits.

e. Carbon-intensive reformation: Shows the estimated production costs for a 660 ton per day SMR project with no CCS, operating at 90% utilization. The spread in values is primarily due to the range in high and low oil price scenarios from the same sources as the low-carbon reformation cost estimates.

f. Production facilities that begin construction before the expiration of the tax credits in 2032 and 2033 will be able to claim the credit for the full 10 years and thus produce hydrogen at the lower estimated LCOH into the 2040s.

Data Sources: ANL, Hydrogen Delivery Scenario Analysis Model (HDSAM), as of February 2024; DOE, *Pathways to Commercial Liftoff: Industrial Decarbonization* (2023); EIA, *Annual Energy Outlook* (2023); LevelTen, *PPA Index*, as of December 2023; McKinsey Hydrogen Insights, as of February 2024; McKinsey Energy Solutions, H2-COM; NETL, "Fossil-Based Hydrogen Production Comparison" (April 2022); NREL, *Annual Technology Baseline* (2023); NREL, H2A-Lite Model, as of February 2024

Figure 12: Estimated hydrogen production costs in $/kg for plants starting construction in 2024-2050. The colored bands correspond to the cost estimates of hydrogen produced via electrolysis—powered by renewables (green) and nuclear (pink)—and via reformation—with (blue) and without (gray) CCS. Estimated costs account for the 45V and 45Q tax credits, applying the larger available cost reduction available between the two cases under each scenario.[23]

22 The range for electrolytic hydrogen production cost estimates is wider today due largely to the variability of technologies (e.g., PEM, alkaline), electricity feedstocks (predominantly wind, solar or a combination of the two), associated electricity prices based on the location and grid intensity, and other factors. At the time of this analysis, 45V final rulemaking is underway. Except where noted, this report's tax credit analyses are based on the guidance as written in the December 2023 45V NPRM.

23 Electricity costs for 2025-2029 use actual VPPA prices currently on the market. While these prices are pre-negotiation, they do not include buffering for peaking capacity. Electricity costs for 2030 onward pull LCOEs from NREL *ATB* 2023.

Increased production costs result in higher delivered costs.[24] For all clean hydrogen pathways, cost reductions are also needed in the midstream for offtake across end use applications.

2030 costs across the value chain if advances in distribution and storage technology are commercialized[a]

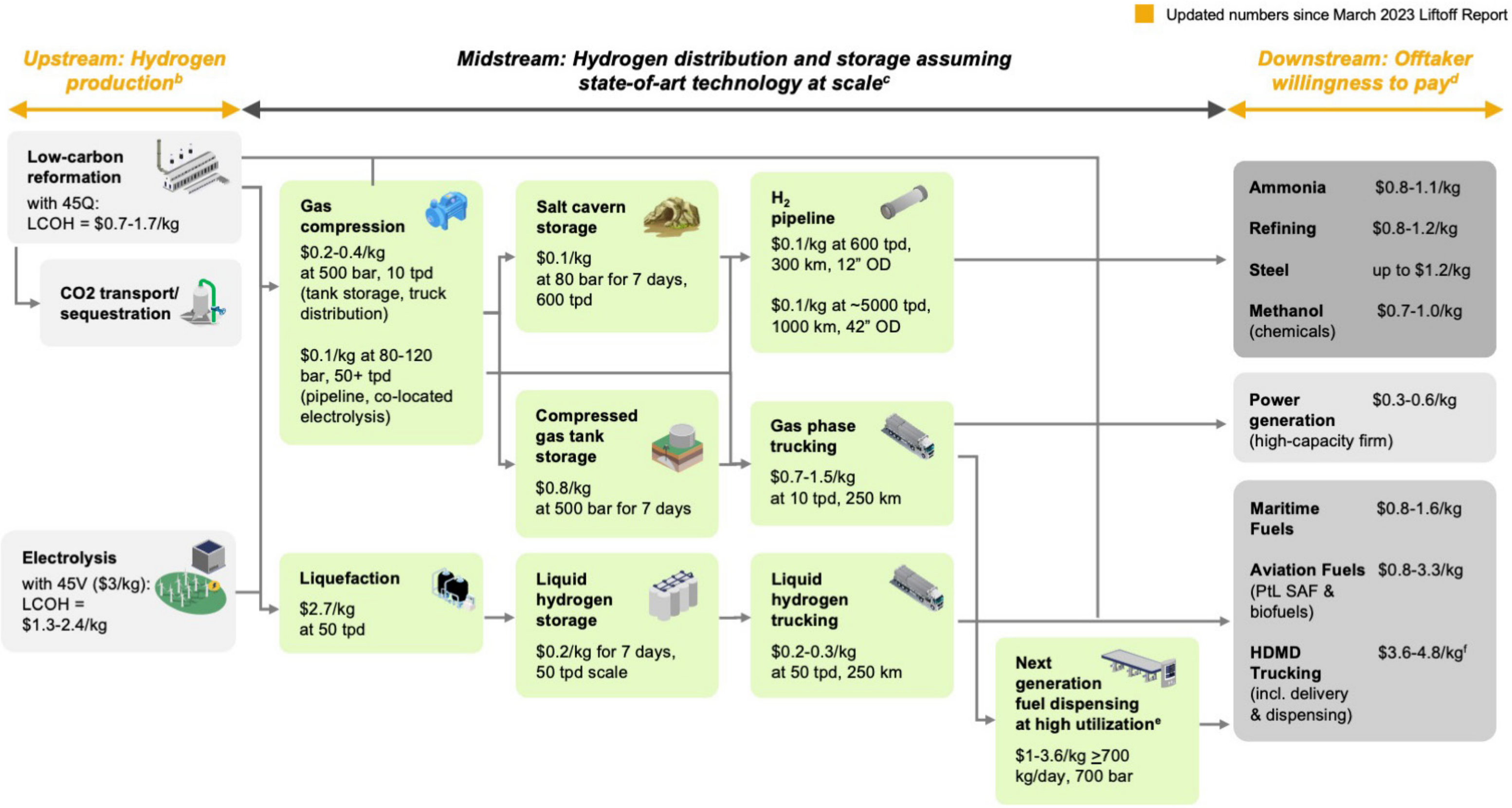


Figure Footnotes:

a. Midstream costs have not been updated from *Commercial Liftoff: Clean Hydrogen* (March 2023) but may be updated in future updates. See appendix of *Commercial Liftoff: Clean Hydrogen* (March 2023) for calculation details.

b. Range based on estimated production costs in different geographies. For low-carbon reformation, the optimized profile of a SMR+CCS new-build in Texas with high oil prices (low) and a SMR+CCS retrofit in California with low oil prices (high). For electrolysis, the optimized profile of a 500 MW PEM facility is based in West Texas (low) and California (high).

c. Data based on cost-downs shared from leading-edge companies who have deployed at demonstration scale (or larger).

d. Defined as the price an offtaker would pay for clean hydrogen vs. fossil alternative.

e. Greater than or equal to 70% utilization, assumes line fill at high pressure.

f. Including delivery and dispensing costs; excluding these costs indicates a breakeven point with conventional, fossil-based alternatives at $1.6-2.8/kg.

Data Sources: ANL, Hydrogen Delivery Scenario Analysis Model (HDSAM), as of February 2024; DOE, *U.S. National Clean Hydrogen Strategy and Roadmap* (June 2023); Hydrogen Council; McKinsey Hydrogen Insights, as of February 2024

Figure 13: Estimated levelized cost of hydrogen (LCOH) in $/kg across multiple hydrogen production, delivery, and storage pathways. The right-hand column shows end user willingness to pay in $/kg over carbon-intensive alternatives. To arrive at a total estimated LCOH for a specific pathway, readers should sum (1) upstream costs and (2) midstream costs to arrive at a potential delivered cost of clean hydrogen, based on the selected production pathway and storage distribution methods. Hydrogen production costs include 45Q or 45V.

24 Since the March 2023 publication of *Commercial Liftoff: Clean Hydrogen*, the costs and assumed utilization rates for midstream infrastructure (pipeline and trucking distribution and storage) have not been updated because estimates have not changed materially at the time of this report.

Section 3: Refreshed View of End Use Applications

KEY TAKEAWAYS

Despite cost increases outlined in Section 2, markets for clean hydrogen are growing. Low-carbon reformation projects can target large, industrial offtakers in ammonia and refining. Electrolysis projects can target end markets with higher willingness to pay or markets with additional, stackable incentives—such as transportation and clean fuels in jurisdictions with low carbon fuel standards or subsidized export markets.

There is a growing market for clean hydrogen produced in the United States. In June 2023, DOE estimated 10 MMTpa of domestic clean hydrogen demand by 2030, predominantly in industrial sectors like ammonia production, refining and chemicals processes. These sectors make up 92% of U.S. hydrogen demand today and provide a direct replacement opportunity for clean hydrogen.[25]

Figure 14 shows a high demand case of 14 MMTpa by 2030 compared to previous DOE estimates.[26] If the three aforementioned industrial sectors continue to grow, and clean hydrogen replaces 100% of fossil-based hydrogen demand, then clean hydrogen's total addressable market could reach 12 MMTpa by 2030.[27] The remaining 2 MMTpa represents upside demand from more nascent applications. These applications, like heavy-duty and medium-duty (HDMD) trucking and power-to-liquid (PtL) sustainable aviation fuel (SAF) will require significant quantities of clean hydrogen, but they require additional technical development and/or midstream infrastructure buildout before reaching demand maturity after 2030. DOE has been investing in several demand-side initiatives, including using a portion of the H2Hubs funding to close the gap between delivered costs and willingness to pay (WTP).[28]

A comparison of end user WTP across these different markets to clean hydrogen production costs further outlines the 2030 clean hydrogen market opportunity. Clean hydrogen's production costs may equal or be lower than end user WTP for certain applications, as illustrated in Figure 14. However, there are additional costs associated with hydrogen transport and storage that are not included in the figure. For example, clean hydrogen might be able to replace some if not all unabated fossil-based hydrogen demand in domestic oil refining (approximately 7.5 MMTpa of demand in 2030) because the maximum WTP is \$0.8-1.2/kg, and developers may be able to sell low-carbon reformation-based hydrogen to refineries at or below this price range, and these facilities may be located near one another to reduce midstream costs.[29]

25 DOE, *U.S. National Clean Hydrogen Strategy and Roadmap* (June 2023).

26 See Appendix 7 for methodology. Note that Figure 13 does not include clean hydrogen demand in export markets.

27 This estimate also includes clean hydrogen demand for forklift operations.

28 In this report, willingness to pay (WTP) refers to the price of clean hydrogen's closest fossil-based alternative at the point ofconsumption. This price point is often seen as a proxy for willingness to pay.

29 Production costs included in Figure 13 do not include the midstream infrastructure requirements to carry out distributed applications (e.g., compression, dispensing, and fueling station maintenance for trucking). As a result, delivered costs of clean hydrogen in 2030 are significantly higher than the production costs illustrated, even when factoring in subsidies like the Alternative Fuel Vehicle Refueling Property Credit, IRA 30C. Additionally, these price and demand estimates represent a moment in time; demand and willingness to pay estimates may change subject to the addition or extension of supportive policies and regulations at both the state level (such as the Low Carbon Fuel Standard [LCFS] in California or the Sustainable Aviation Fuel [SAF] Tax Credit in Illinois) and the federal level (such as the Inflation Reduction Act Section 45Z). For more information on the assumptions used in Figure 13, see Appendix 7.

Clean hydrogen produced via low-carbon reformation may appeal to large, industrial offtakers in 2030. Clean fuels represent a nascent but growing market with high WTP.

Domestic clean hydrogen demand and willingness to pay vs. production costs, including production and demand subsidies, 2030[a], $/kg

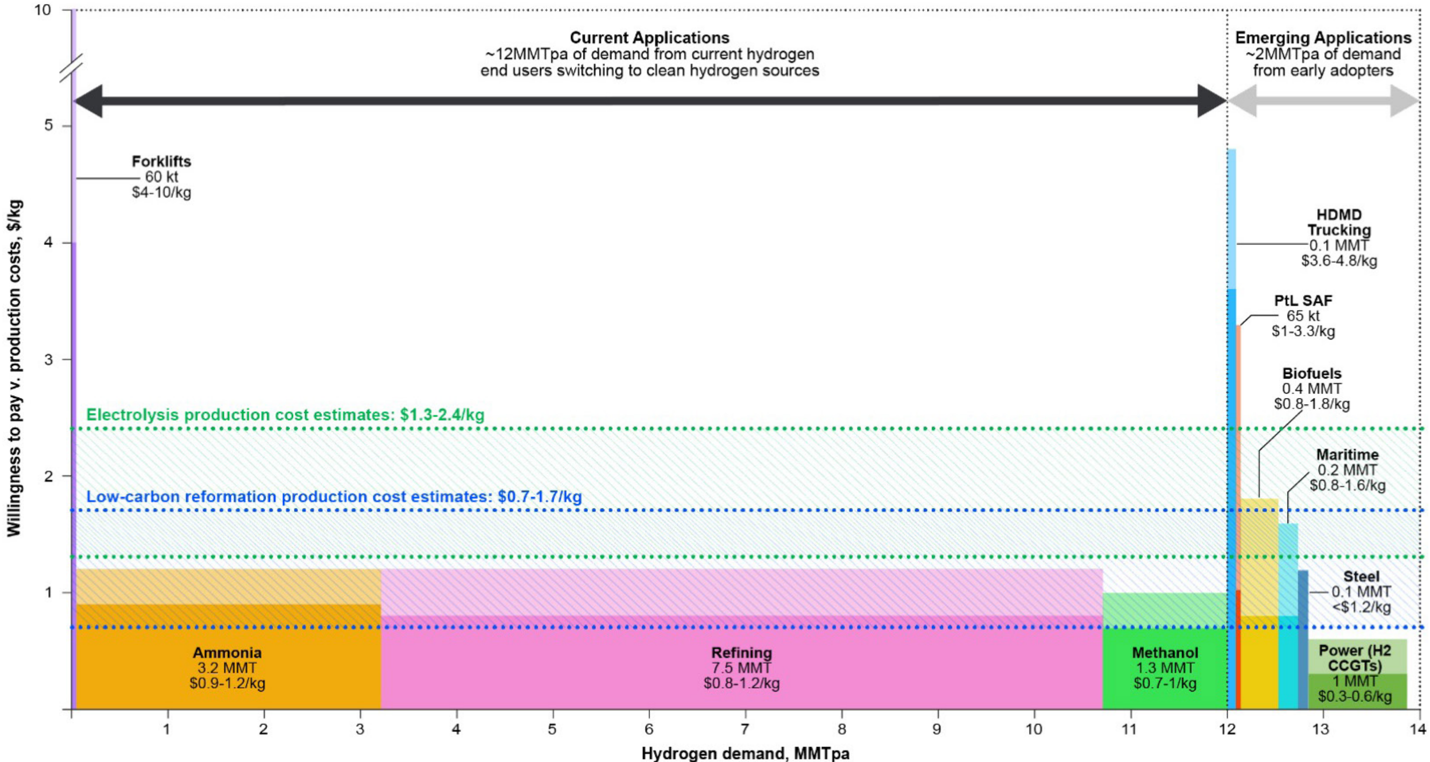


Figure Footnotes:

a. See Appendix 7 for detailed assumptions for 2030 WTP and demand estimates. Note, these depict a single scenario for 2030 while the *U.S. National Clean Hydrogen Strategy and Roadmap* depicts a range of scenarios out to 2050 in a similar figure and excluded refining to illustrate reduction of petroleum use.

b. Demand upside is dependent on the continuation and/or expansion of technical development, investment and supportive policy.

c. HDMD trucking requires additional midstream infrastructure buildout. "Production costs" do not cover refueling infrastructure needed to service this use case; 2030 costs at the pump are estimated $15/kg, depending on subsidies.

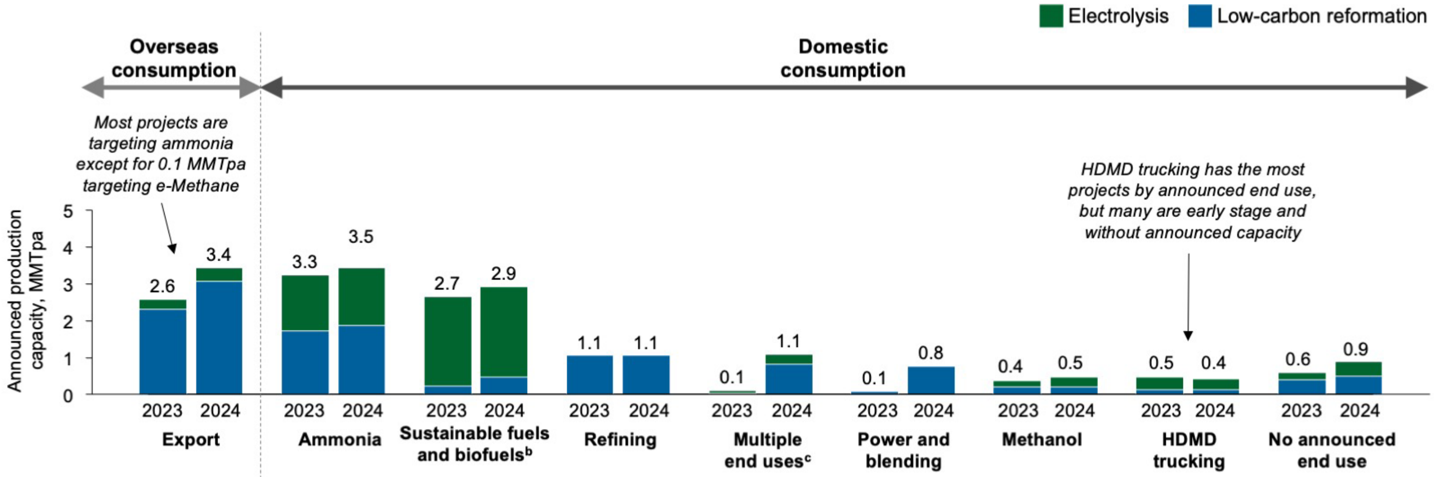
Data Sources: ANL, Hydrogen Delivery Scenario Analysis Model (HDSAM), as of February 2024; LevelTen, *PPA Index*, as of December 2023; McKinsey Energy Solutions, H2 Cost Optimization Model (H2-COM); McKinsey Hydrogen Insights, as of February 2024; NETL, Fossil-Based Hydrogen Production Comparison (April 2022); NREL, *Annual Technology Baseline* (2023); NREL, H2A-Lite Model, as of February 2024; See Appendix 7 for demand and WTP assumptions and sources

Figure 14: Clean hydrogen demand estimates in 2030, broken out by end use application. The height of each bar indicates the estimated willingness to pay (WTP) in $/kg while each bar's width indicates the estimated 2030 hydrogen demand for each end market in MMTpa. Demand is divided into current and more nascent markets and organized in order of decreasing WTP (from left to right) in each. The blue and green rectangles extending horizontally across the figure indicate the high and low cost estimates for electrolytic (green) and low-carbon reformation-based (blue) hydrogen production in 2030. Where these bars intersect with WTP ranges indicates applications for which clean hydrogen be commercially viable. See Appendix 7 for more detailed methodology on 2030 WTP and demand estimates.

Developers are already targeting end markets that can accommodate their production costs, enabling liftoff (Figure 15). Within the domestic market, there has been a growth in electrolytic capacity going toward SAF and biofuels, given stackable incentives like the Illinois SAF Credit and state-level low-carbon fuel standards, which can bring down prices relative to unabated fossil-based alternatives and relative to cheaper clean hydrogen production pathways. For a deeper dive on SAF markets and incentives, please refer to the *Pathways to Commercial Liftoff Sustainable Aviation Fuel* (2024) report. Low-carbon reformation project developers can capitalize on their comparatively lower production costs and target large industrial offtakers in the industrial and chemicals spaces. Hydrogen exports, typically in the form of ammonia, make up 25% (3.4 MMTpa) of proposed offtake. In the last year, some low-carbon reformation-based ammonia projects have shifted offtake targets from domestic to international markets—given both the considerable demand-side support in Europe and Japan and the competitive production cost profile of American producers (Figure 16).

Over the last year, clean hydrogen project developers have targeted offtakers whose WTP most closely matches the costs of their selected production pathway.

U.S. announced clean hydrogen projects by target end use sector (excluding H2Hubs)[a], MMTpa



	Export	Ammonia	Sustainable fuels and biofuels[b]	Refining	Multiple end uses[c]	Power and blending	Methanol	HDMD trucking	No announced end use
# of projects (2024)	13	25	13	5	17	25	4	38	55
% increase in projects from March 2023 Liftoff Report[d]	35%	(20%)	(15%)	0%	900%	500%	10%	(8%)	200%

Figure Footnotes:

a. Includes projects without an announced commercial operation date (COD). Data is shown for January of the year listed. Excludes projects with an announced COD beyond 2030. In *Commercial Liftoff: Clean Hydrogen* (March 2023), projects with an announced COD beyond 2030 were included, resulting in roughly 1MMTpa higher capacity reported. Not inclusive of projects associated with DOE's H2Hubs.

b. Includes sustainable fuels and biofuels as well as fuel cell–based transport.

c. Represents production capacity that is targeting more than one of the other end use sectors.

d. Compared to *Commercial Liftoff: Clean Hydrogen* (March 2023).

Data Sources: McKinsey, Hydrogen Insights Project and Investment Tracker, as of January 2024

Figure 15: Announced clean hydrogen production projects (excluding H2Hubs) by target sector and production pathway. The height of each bar indicates the total size of projects in MMTpa while the color indicates the production pathway with electrolysis in green and low-carbon reformation in blue. The number of projects as of 2024 and the percent increase in projects from the March 2023 *Commercial Liftoff: Clean Hydrogen* report are provided below each bar.

Export markets could provide additional demand that will help scale both low-carbon reformation-based and electrolytic hydrogen production methods. Japan's contracts-for-differences mechanism includes up to 3 trillion yen (~$19B) for low-carbon reformation-based hydrogen and could present a 3 MMTpa export opportunity for American producers by 2030. In particular, the proposed Japanese contract for differences program that includes low-carbon reformation-based hydrogen could be a significant export opportunity for American producers. Similarly, recent legislation[30] in Europe may directly and indirectly increase end user WTP for electrolytic hydrogen powered by renewables through binding industrial, transport, and energy sector targets, creating a 10 MMTpa export opportunity.

The United States has several advantages for clean hydrogen production, such as low-cost natural resources including renewables capacity for electrolysis, low-cost natural gas, and available geologic sequestration formations for storing carbon captured from reformation. U.S. production tax credits have made domestically produced clean hydrogen much more competitive globally. These comparative advantages manifest as an opportunity for the U.S. to become a significant exporter of clean hydrogen by 2030 (Figure 16).

Of the countries analyzed in this report update, the United States could potentially produce and export the lowest cost clean hydrogen (via low-carbon reformation) as well as the lowest cost electrolytic hydrogen by 2030.[30]

Estimated 2030 landed costs of hydrogen export to Japan and the Netherlands[a], $/kg

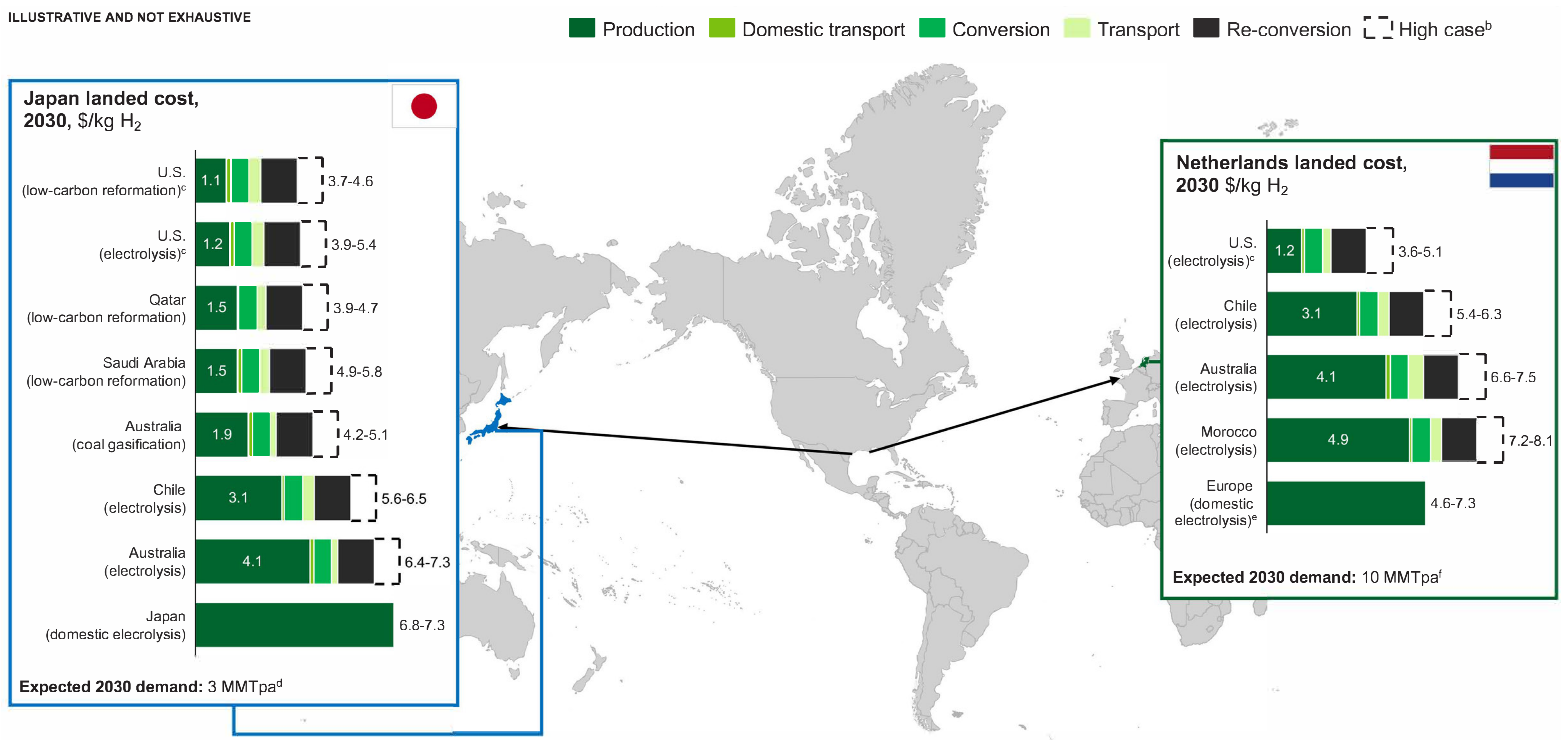


Figure Footnotes:

a. See assumptions in Appendix 6. No incentives are included in this analysis, with the exception of 45V and 45Q for clean hydrogen produced in the United States.

b. High case range based on ammonia re-conversion powered by the grid or burning hydrogen onsite.

c. U.S. cases assume West Texas clean hydrogen production with pipeline transport from the site of production to the ports in the Gulf Coast. U.S. landed costs are inclusive of 45Q (estimated $0.5/kg) and 45V (estimated $1.7/kg) subsidies for low-carbon reformation and electrolysis, respectively.

d. Estimate based on the proposed national hydrogen strategy.

e. Range includes production costs for different countries including Spain, Germany and the Netherlands.

f. Estimated based on Renewable Energy Directive III legislation.

Data Sources: Updated from Hydrogen Council, Global Flows Model (November 2023)

Figure 16: Estimated landed costs of hydrogen exports in $/kg from the United States and other clean hydrogen producers compared to local production in Japan and the E.U. in 2030.[31] The colors of each bar indicate the cost-contribution category for production, conversion, transport, reconversion and the dashed addition indicates an estimated high case cost for reconversion. Selected countries do not represent active trade agreements nor any import/export taxes on clean hydrogen.

At the same time, countries are developing policies and trade agreements to improve domestic competitiveness, which may affect U.S. export opportunities. For example, in June 2024, Japan and the European Union agreed to develop standard policies on clean hydrogen supply and demand in an effort to establish an international commodity market. Additionally, although South Korea is also developing a contracts-for-difference program similar to Japan, which could result in up to 2 MMTpa of clean hydrogen imports, it is also considering production tax credits in order to shore up domestic production.

30 Selected countries include countries with current and planned clean hydrogen production; not all countries were included in the analysis. These cost estimates represent a point of time in 2030 and assume same capital cost of conversion for labor across all scenarios, and the same electrolyzer capex among non-U.S. electrolysis projects. See Appendix 6 for more detail.

31 The U.S. production costs are inclusive of 45V and 45Q credits, whereas other country estimates do not include any hydrogen production subsidies.

Section 4: Promising Pathways

KEY TAKEAWAYS

Emerging pathways like methane pyrolysis might accelerate liftoff given their potential to produce clean hydrogen at lower costs and/or at lower emissions levels.

Currently, roughly 95% of U.S. hydrogen production is from carbon-intensive reformation. Much of the March 2023 *Commercial Liftoff: Clean Hydrogen* report and this 2024 report update focuses on two pathways for clean hydrogen production: low-carbon reformation and electrolysis. However, additional hydrogen sources and technologies may have a role to play in the clean hydrogen economy.

There are additional promising clean hydrogen production pathways, including but not limited to methane pyrolysis, geologic extraction, and chlor-alkali processes.

Pathway	Production Process	LCOH	Target Industries	U.S. Market Size	Considerations
Methane Pyrolysis	Hydrogen and other carbon byproducts (carbon black, graphite, carbon nanofibers, etc.) are produced when natural gas is heated in an inert environment	**$4-5/kg** H_2 only; ***$1.3-1.7/kg*** *H_2 + byproducts (dependent on carbon quality)*	Cement, steel, metallurgy, and plastics (dependent on demand)	**~0.1 MMTpa** H_2 demand associated with current carbon black market	Carbon intensity and cost of production are highly dependent on electricity source and feedstock
Geologic Hydrogen	Hydrogen is produced via radiolysis of water with iron-rich rock at high temperatures underground and can be extracted from the earth, similarly to natural gas	**$4-5/kg** initially; **$0.5-1/kg** at-scale (preliminary; no commercial operations in the U.S. to date)	Likely industrial offtakers that can be co-located or connected to extraction site	Estimated in-place global resources range from thousands to billions of megatons; Market size constrained to extractable, economic resources	Resource potential and location are still to be determined; High uncertain probability that geologic hydrogen occurs in economic accumulations; Purity considerations based on release of collocated gasses
Chlor-Alkali Production	Clean hydrogen is produced as a byproduct via electrolytic reaction with sodium chloride in water	**Negligible** (H_2 is a byproduct)	50% of H_2 produced on-site is combusted to power the chlor-alkali process, the remainder is vented and can be repurposed or resold	**0.7 MMTpa** H_2 based on demand for chlorine gas and caustic soda	Given the market maturity of chlor-alkali, it is unlikely there will be meaningful additional H_2 capacity for additional use cases

Figure 17: Description of several additional clean hydrogen production pathways with estimated levelized cost of hydrogen (LCOH), target industries, market size, and other key considerations.

- **Methane pyrolysis** converts natural gas to hydrogen and carbon byproducts. Carbon byproducts of methane pyrolysis include carbon black (a chemical compound added to rubber to make car tires) and graphite (a chemical compound used to make pencils, batteries, solar panels, and steel). Carbon black is the most commercially mature byproduct of methane pyrolysis. The current market for domestic carbon black supports the production of 0.1 MMTpa of clean hydrogen via pyrolysis. Globally, carbon black demand limits the total addressable market of clean hydrogen produced by methane pyrolysis to approximately 4 MMTpa without additional markets. For methane pyrolysis to scale carbon byproducts with higher demand volumes, like graphite or plastic or steel, must be unlocked.[32] Additional considerations for methane pyrolysis include CI levels, as it requires significant quantities of power to support required plasma reactors. Methane pyrolysis can have a wide range of CI scores; this pathway can be considered clean depending on the power source and feedstock used.

32 Marc von Keitz, "Methane Pyrolysis for Hydrogen–Opportunities and Challenges," presentation for the Hydrogen Shot Summit: Thermal Conversion with Carbon Capture & Storage, Advanced Research Projects Agency–Energy (ARPA-E), August 31, 2021.

- **Geologic hydrogen** is a potentially inexhaustible source of clean hydrogen, produced when iron-rich rocks interact with water beneath the Earth's crust. Large quantities of hydrogen gas may exist naturally in the Earth today; however, the potential for economic accumulations of this natural hydrogen is still unknown. Efforts are also underway to stimulate the production of hydrogen gas in the subsurface—a process that takes only a matter of years—by repurposing existing and retired oil wells and by adding water to sites with ultramafic (source) rocks.

  Geologic hydrogen—whether naturally or synthetically produced—can be extracted using processes similar to the extraction of natural gas. Extraction may require less energy, water, and capital than clean hydrogen produced via electrolysis or low-carbon reformation. The carbon intensities of extraction may vary depending on the existence and treatment of co-located gases (e.g., methane or nitrogen). The costs of extraction, too, vary depending on the resource location.

  There is considerable research underway in both the United States and internationally to explore resource locations, co-located gases, extraction potential and associated costs.[33] In the U.S., exploration testing is underway, although no companies have started commercializing.[34] More information can be found in *Science Advance's* December 2024 publication from the U.S. Geological Services Energy Resources Program.

- **Chlor-alkali processes** involve the simultaneous production of chlorine, caustic soda solution, and hydrogen. This process is part of a mature industry dating back more than 70 years and currently generates roughly 0.7 MMTpa of clean hydrogen as a byproduct. The cost of production is so low largely because of the mature and considerable scale of operations to date; however, given the maturity of the chlorine industry it is unlikely that chlor-alkali will be scaled further.

33 "U.S. Department of Energy Announces $20 Million To Explore Potential of Geologic Hydrogen," ARPA-E Press Release, September 7, 2023.

34 Sheila McCafferty Harvey and Elina Teplinsky, "Natural Hydrogen May Seem New in Town, but It's Been Here All Along," JDSupra (website), March 26, 2024.

Appendices

Appendix 1: Key Terminology and Abbreviations

45Q Tax Credit (45Q): A tax credit modified by the *Inflation Reduction Act of 2022* that provides tax incentives for carbon capture and sequestration. The credit has a 12-year claim period and ranges in value from $60–85/metric ton CO_2 depending on how the captured CO_2 is stored/used. These credit values assume the prevailing wage and apprenticeship requirements are met.

45V Production Tax Credit (45V or 45V PTC): A 10-year tax credit created by the *Inflation Reduction Act of 2022* that provides a tax incentive for clean hydrogen production. The credit is divided into four tiers with higher credits applied when lifecycle greenhouse gas emissions of the H_2 production is lower. Lifecycle greenhouse gas emissions of <0.45 kg CO_2e/kg H_2 corresponds to a $3/kg credit, 0.45–1.5 kg CO_2e/kg H_2 to a $1/kg credit, 1.5–2.5 kg CO_2e/kg H_2 to a $0.75/kg credit, and 2.5–4 kg CO_2e/kg H_2 to a $0.60/kg credit. These credit values assume that prevailing wage and apprenticeship requirements are met.

Alkaline (ALK) Electrolyzer: Electrolyzer that creates hydrogen using electricity by transporting hydroxide ions through an electrolyte, typically a liquid alkaline solution. These electrolyzers are a cost-effective and mature technology; however, they have low current density and a corrosive electrolyte. They are currently used for industrial applications, including ammonia, refining, steel, and chemicals.

Autothermal Methane Reformation (ATR): A similar approach to producing hydrogen as Steam Methane Reformation. When combined with carbon capture and sequestration (CCS), ATR is expected to cost less than SMR+CCS, especially at commercial scales and in regions with low-cost electricity because it integrates an air separation unit with the reforming process to improve thermal efficiency and enable higher capture rates and lower-cost. ATR is nascent in the U.S. today but growing as a proportion of announced reformation-based projects.

Clean Hydrogen Liftoff (Liftoff): The point at which clean hydrogen projects are sustained at a total cost of ownership breakeven point with fossil-based alternatives. When Liftoff is capitalized, it refers to the DOE's Pathways to Commercial Liftoff reports and broader initiative.

Combined Cycle Gas Turbine (CCGT): A natural gas powered turbine consisting of a simple cycle gas turbine combined with a second steam turbine.

Commercial Operation Date (COD): The date on which a project begins commercial operations.

DOE H2Hubs: The 7 Regional Clean Hydrogen Hubs either selected or awarded funding by the Department of Energy through the Bipartisan Infrastructure Law. These Hubs are located around the United States and leverage different hydrogen production methods and feedstocks. These 7 Hubs collectively represent $7 billion of the $8 billion Regional Clean Hydrogen Program; the remaining funding is dedicated to a demand-side support initiative.

Electrolysis: The process of using electricity to split water into hydrogen and oxygen.

Final Investment Decision (FID): The point in a project development funnel at which major financial commitments are made; FID+ refers to projects that have signed these agreements and are in construction.

Front-End Engineering Design (FEED): The stage at which a project plan includes a plan of execution and detailed budget in advance of funding approval to identify risks.

Levelized Cost of Electricity (LCOE): The present value of the total cost of electricity generated or purchased to supply clean hydrogen production, converted into equal annual payments and adjusted for inflation—often described on a per kWh basis.

Levelized Cost of Hydrogen (LCOH): The present value of the total cost of building and operating a hydrogen production plant over its life (estimated 25 years for electrolyzers and 40 years for reformers), converted into equal annual payments and adjusted for inflation—often described on a per kilogram basis.

Low Carbon Fuel Standard (LCFS): A state-level emissions trading rule in California, Washington, and Oregon designed to reduce the CI of transportation fuels.

Low-Carbon Reformation (SMR/ATR+CCS): The application of decarbonization levers to traditional reformation (SMR or ATR) technologies.

Unless where noted, this report refers to the addition of CCS technologies; Amine-based solvents can capture more than 90% of point-source emissions and can add up to $0.4/kg to production costs, depending on geography and availability of storage infrastructure, capture rates, and other factors.

Million Metric Tons per annum (MMTpa): Quantity used to define capacity (production, demand) of clean hydrogen and/or other outputs; 1 metric ton is equivalent to 1,000 kilograms (kg). *Note: This 2024 report update sometimes refers to ktpa in smaller-scale applications.*

Notice of Proposed Rulemaking (NPRM): A public notice posted in the Federal Register that is required when a U.S. federal agency wishes to add, remove, or change a rule or regulation. This notice creates an opportunity for the public to comment upon the proposed rule prior to final rulemaking. In this report, NPRM refers to the Inflation Reduction Act's clean production tax credit (45V), the notice of which was published in December 2023.

Power Purchase Agreement (PPA): A long-term contract between an electricity generator (power) and a customer (purchaser).

Proton Exchange Membrane (PEM) Electrolyzer: Electrolyzer that produces hydrogen using electricity by transporting positively charged hydrogen ions through an electrolyte made of a solid specialty plastic material. These electrolyzers have a simple cell design, small footprint, high dynamic response, and high current density; However, they rely on polyfluoroalkyl substances (PFAS) chemicals, rare/expensive materials, and have less demonstrated long-term durability compared to other electrolyzers. Potential applications of these electrolyzers include road transport, distributed hydrogen production, and grid balancing.

Renewable Energy Sources (RES): Supply of renewable energy.

Renewable Natural Gas (RNG): Biogas resulting from the decomposition of organic matter from a variety of sources—including landfills, digestors, livestock farms, food production facilities, and others—that has been upgraded to a quality similar to fossil natural gas and can be used in reformation processes.

Solid Oxide Electrolysis Cell (SOEC): Electrolyzer made of a solid ceramic material that creates hydrogen using electricity by selectively conducting negatively charged oxygen ions at high temperatures—often from a lightwater nuclear reactor. SOEC electrolyzers are a more nascent technology with applications in low purity industrial use cases. SOEC electrolyzers have a low electricity demand but require a heat/steam source, have limited dynamical response, and durability challenges with high-temperature operations. *Note: Outside of Figure 1, SOEC electrolysis is not included in this report given the relative nascence of the technology.*

Steam Methane Reformation (SMR): The conversion of methane and high-temperature steam into hydrogen and carbon monoxide. Associated carbon intensities vary depending on the natural gas feedstock and delivery, leakage, and the electricity source. SMR accounts for nearly all commercially produced hydrogen in the United States.

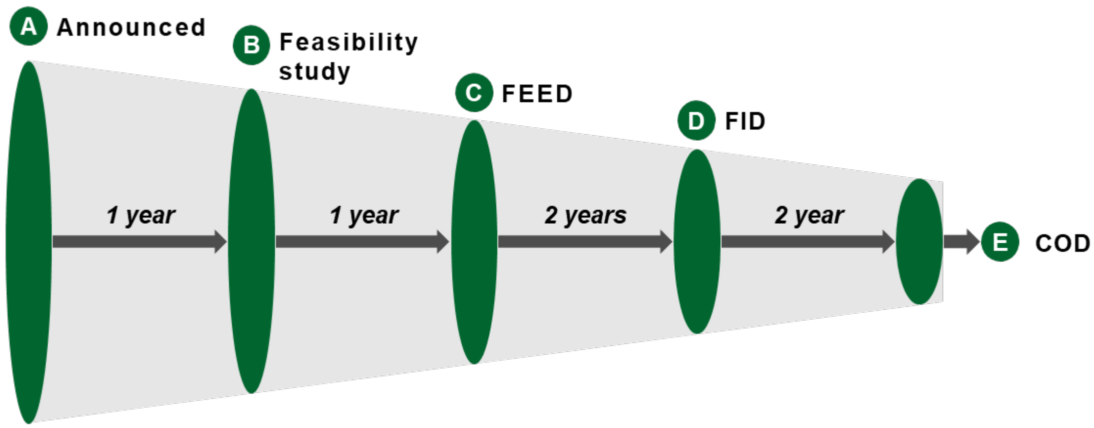
Sustainable Aviation Fuel (SAF) Credit: A tax credit was created by the *Inflation Reduction Act of 2022,* Section 40B, for tax years 2023 and 2024. This credit provides $1.25 for each gallon of SAF in a qualified mixture. To qualify, the SAF must have a minimum reduction of 50 percent in lifecycle greenhouse gas emissions compared to petroleum-based jet fuel. The credit can be increased by an additional $0.01 per gallon for each additional 1 percent reduction in lifecycle greenhouse gas emissions beyond 50 percent, up to $0.50 per gallon. The SAF credit will be replaced by the 45Z clean fuels credit in 2025-2027.

Total Cost of Ownership (TCO): The total costs incurred by a customer over the lifetime of using an application—including capital, operating, and financing costs—converted into equal annual payments and adjusted for inflation. For example, the TCO for fully delivered hydrogen fuel at a refueling station for a hydrogen fuel cell electric vehicle driver might be >$4/kg. *Note: There are many assumptions embedded into TCO analyses across hydrogen production, midstream, and end use, and these analyses are meant to be directional.*

Virtual Power Purchase Agreement (VPPA): A long-term contract between an electricity generator and a customer in which the customer receives renewable energy credits rather than the power directly.

Willingness To Pay (WTP): The maximum price an offtaker will pay for a single unit of hydrogen or its derivatives or the estimated price at which clean hydrogen is as expensive or less expensive than its traditional, fossil-based alternative before a change in demand occurs.

Appendix 2: Project Development Funnel Risk-Adjustment Methodology



Project type	Success factors between development stages			
H2Hub w/ COD	50%	65%	90%	98%
H2Hub w/o COD	40%	60%	90%	98%
Non-Hub w/ COD	40%	60%	90%	98%
Non-Hub w/o COD	30%	55%	90%	98%

Figure A1: Project development funnel illustration and success factor assumptions between development stages.

Methodology

Success factors are derived from offshore wind project development, supplemented with input from key stakeholders in the U.S. clean hydrogen economy.

For projects with no COD listed, CODs were assigned 6-8 years after announcement date, whereby 25% of capacity will be online after 6 years, 50% of additional will be online within 7 years and the remaining 25% of capacity will be online within 8 years.

Some projects were re-assigned COD based on their announcement date if their timeline was deemed faster than shown/reasonable (i.e., faster than 6 years).

Projects announced in 2023 were assumed to be online by the end of 2029.

Appendix 3: Required Investments Across the Value Chain Methodology

Required investments across the value chain were calculated using the method outlined in the November 2021 Hydrogen Council report *Hydrogen for Net-Zero: A Critical Cost-Competitive Energy Vector* and the hydrogen demand forecasts for the Net Zero 2050—high renewable energy scenario and the hydrogen spike case scenarios. The production pathway split between electrolysis and low-carbon reformation was calculated from McKinsey's Project and Investment tracker using projects with announced CODs. These data are used to determine the upstream production capex investment requirements and net new low carbon energy production investment requirements. Additional announced H2Hubs investment was added based on internal DOE forecasts without segmentation to specific value chain steps. The Hydrogen Council methodology is summarized below.

Hydrogen value chain direct investment requirement

This analysis presents a novel view of the direct investments required to realize the projected hydrogen economy. It employs detailed hydrogen application TCO models and hydrogen cost and investment data collected from Hydrogen Council Members through a clean team—please refer to *Path to Hydrogen Competitiveness: A Cost Perspective* (January 2024) and *Hydrogen Insights* (May 2023). The analysis considers three main value chain steps: hydrogen production; hydrogen midstream infrastructure, which includes distribution, storage, and conversion; and end use infrastructure.

Hydrogen production

Estimates include the investments required to build out new electrolysis and low-carbon reformation production capacity in terms of electrolyzers and natural gas reformers with required carbon capture equipment. Further, it considers the investments required for the conversion of existing reformation-based production capacity without carbon capture to low-carbon production. It also calculates the upstream energy investments required to build out net new low carbon energy production.

Hydrogen midstream infrastructure

The March 2023 *Commercial Liftoff: Clean Hydrogen* report and this 2024 report update derive investment requirements from segment-specific estimates accounting for three types of conversion processes of varying sizes (gas compression, liquefaction, and ammonia conversion/cracking). The investment requirements also consider three types of distribution: pipelines, gaseous trucking, and liquid-phase trucking of varying sizes and distances.

Hydrogen end-applications

Downstream investments include equipment and plants required to support hydrogen demand across applications. In transportation, for example, fuel cells, hydrogen tanks, and refueling infrastructure are included. Other equipment includes turbines, generators, plant investment for conventional industrial applications like ammonia and methanol production, and newer hydrogen applications like steel production.

Key inputs and assumptions

Required investments were calculated based on the hydrogen demand scenarios described in the hydrogen demand forecasts for the Net Zero 2050. The forecasted number of dedicated hydrogen pipeline miles and the distribution of pipeline diameters over time used to calculate the required pipeline investment were input from NREL's Scenario Evaluation and Regionalization Analysis (SERA) model.

Objectives of analysis

Illustrate investment associated with announced hydrogen projects and identify capital gap through 2030 across 1) net new low carbon energy production, 2) hydrogen production, 3) midstream infrastructure, and 4) end use infrastructure.

Considerations and limitations of approach

These investments do not include indirect value chain investments, such as factories, mines, and R&D expenses. H2Hubs investment do not have disclosed value chain split information. For fuel cell–based trucks, the value of the truck and buildout of the refueling infrastructure is included in required investments, but the supply chain and manufacturing costs for the truck is not included.

Appendix 4: Build Mix Scenario Assumptions Based on 45V NPRM

- ***U.S. assumptions:***
  Assumes 500 MW PEM facility with salt cavern geologic storage and a dedicated H_2 pipeline connecting production with the storage location to provide 95% firm H_2; assumes 25-year asset lifetime, WACC of 10% (pre-2030) and 7% (2030 onwards); 2025 electrolyzer capex ($1,848/kW) is based on weighted average for PEM projects; 2030 ($1,494/kW), 2040 ($1,277/kW) and 2050 ($1,125/kW) is based on estimates about U.S. electrolyzer deployments and learning rates (see Appendix 5); LevelTen PPA Index data is used (except where noted) for 2025 electricity levelized costs, while NREL ATB 2023 LCOE data is used for 2030 onwards; assumes excess power production can be sold back to the grid at $20/MWh based on typical ERCOT real-time market prices during times of peak RES generation; $15/MWh average transmission and distribution (T&D) is assumed for RES that is not co-located with electrolysis; assumes 100 bar salt cavern geologic storage with $40/kg stored capex, 3-day storage, 40% cushion case, and low utilization (22-30%) pipeline with maximum flow rate of 10 tons per hour (based on transmission and storage of full 500 MW electrolyzer peak hourly capacity). For electrolytic cost and CI ranges, West Texas often represents the high-CI and low-cost end of range, whereas Southern California often represents the low-CI and high-cost end of the range. These two regions are analyzed because they host most of the announced/planned clean hydrogen capacity and are not necessarily the absolute highest/lowest cost or the most/least carbon intensive.

  - ***West Texas:*** 2025 optimal build mix: 1.0-1.4-1.0 solar-wind-electrolyzer ratio, 68% blended optimized capacity factor, $58/MWh solar PPA price, and $36/MWh wind PPA price; 2030 and onwards optimal build mix: 0.9-1.5-1.0 solar-wind-electrolyzer ratio, 66% blended optimized capacity factor; 2030 and onwards assumed LCOEs: $40/MWh (Class 1 solar, inclusive of T&D adder, 2030), $21/MWh (Class 1 wind, 2030), $34/MWh (Class 1 solar, inclusive of T&D adder, 2040), $19/MWh (Class 1 wind, 2040), $31/MWh (Class 1 solar, inclusive of T&D adder, 2050), $17/MWh (Class 1 wind, 2050); assumes wind co-located with electrolysis and solar sourced from within ERCOT through a VPPA; assumes 200-mile pipeline connecting production and storage.
  - ***Southern California:*** 2025 optimal build mix: 1.2-1.1-1.0 solar-wind-electrolyzer ratio, 59% blended optimized capacity factor, $45/MWh solar PPA price, and $85/MWh wind PPA price; 2030 and onwards optimal build mix: 1.2-1.0-1.0 solar-wind-electrolyzer ratio, 56% blended optimized capacity factor; 2030 and onwards assumed LCOEs: $25/MWh (Class 1 solar, 2030), $51/MWh (Class 9 wind, inclusive of T&D adder, 2030), $19/MWh (Class 1 solar, 2040), $48/MWh (Class 9 wind, inclusive of T&D adder, 2040), $16/MWh (Class 1 solar, 2050), $44/MWh (Class 9 wind, inclusive of T&D adder, 2050); assumes solar co-located with electrolysis and wind sourced from within CAISO through a VPPA; assumes 200-mile pipeline connecting production and storage.
  - ***New Jersey:*** 2025 optimal build mix: 0.6-1.4-1.0 solar-wind-electrolyzer ratio, 60% blended optimized capacity factor, $86/MWh solar PPA price, and $61/MWh wind PPA price; 2030 and onwards optimal build mix: 0.7-1.3-1.0 solar-wind-electrolyzer ratio, 62% blended optimized capacity factor; 2030 and onwards assumed LCOEs: $48/MWh (Class 7 solar, inclusive of T&D adder, 2030), $36/MWh (Class 9 wind, 2030), $39/MWh (Class 7 solar, inclusive of T&D adder, 2040), $33/MWh (Class 9 wind, 2040), $35/MWh (Class 7 solar, inclusive of T&D adder, 2050), $30/MWh (Class 9 wind, 2050); assumes wind co-located with electrolysis and wind sourced from within PJM through a VPPA; assumes 280-mile pipeline based on nearest available salt cavern to New Jersey.
  - ***Illinois:*** Assumes 95% capacity factor nuclear power and no additional H_2 storage; power prices use PJM power price futures as a proxy for an existing nuclear plant, including any T&D costs; assumed power prices are $48/MWh (2025) and $54/MWh (2029 onwards).

Data Sources: ANL, Hydrogen Delivery Scenario Analysis Model (HDSAM), as of February 2024; LevelTen, *PPA Index* as of December 2023; McKinsey Hydrogen Insights, as of February 2024; McKinsey Energy Solutions, H2 Cost Optimization Model (H2-COM); NREL, *Annual Technology Baseline* (2023) NREL, H2A-Lite Model, as of February 2024; S&P CapitalIQ

Appendix 5: Electrolyzer Capex Estimates and Forecasts

Electrolyzer capex estimates are expected to decrease by 41% by 2050 due to continued and increased deployments and associated learning curves. Table A1 indicates capex estimates resulting from both U.S. deployments and associated learning rates. R&D advances through the Hydrogen and Fuel Cell Technologies Multi-Year Program Plan could further drive down system costs.

Capex (2022$/kW)	
2025	$1,848
2030	$1,494
2040	$1,277
2050	$1,125

Table A1: PEM electrolyzer capex estimates for 500 MW projects, based on cumulative installed capacity in the US.

Data Sources: Learning Curves: Evan P. Reznicek, Mariya N. Koleva, Jennifer King, Matthew Kotarbinski, Elenya Grant, Sanjana Vijayshankar, Kaitlin Brunik, Jared Thomas, Abhineet Gupta, Steven Hammond, Vivek Singh, Richard Tusing, Pingping Sun, Kyuha Lee, Amgad Elgowainy, Hanna Breunig, Fabian Rosner, and João Pereira Pinto, "Techno-economic analysis of low-carbon hydrogen production pathways for decarbonizing steel and ammonia production," Cell Reports Sustainability, 2025, forthcoming. Deployment Estimates: Based on the Stated Policies Scenario from IEA, Global Hydrogen Review, 2024.

Deployment Rates

This analysis leverages the "Stated Policies" scenario outlined in IEA's 2024 Global Hydrogen Review report, as it most directly aligns with Liftoff's electrolyzer deployment forecasts.

In 2025, Liftoff estimates 2 GW of deployment. As of 2024, 4.5 GW of electrolysis capacity is planned for installation in the U.S. (S. Satyapal, 2024, AMR Plenary Presentation, slide 20, U.S. DOE Hydrogen Program Annual Merit Review (AMR) Plenary Remarks). 2 GW of deployment in 2025 would assume that 44% of this planned 4.5 GW of capacity will have been installed by 2025.

Liftoff estimates between 10-11 GW of electrolyzer deployment, assuming 1.9 MMTpa of electrolytic hydrogen production comes online by 2030. This assumes 55 kWh of electricity per kg of hydrogen produced.

Future installed capacity estimates are based upon estimates from Liftoff's clean hydrogen production capacity estimates as well as global market growth trends from the Stated Policies scenario in IEA's Global Hydrogen Review 2024.

Learning Rates

Electrolysis learning rates are based upon recent analysis from NREL.[35] The learning rates are distinct for different system sub-components and for installation costs. Capex per component is determined with reference to a total installed capex of $1,850/kW in 2022$ for 2025, as indicated in Table A2 and shown graphically in Figure A2. Variables indicated in the table correspond to the following general learning function, where CV is the capital cost ($/kW) at a cumulative installed capacity V (GW):

$$C_V = C_o(1 - LR)^{ln\left(\frac{V}{Vo}\right)/ln(2)}$$

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35 Evan P. Reznicek, Mariya N. Koleva, Jennifer King, Matthew Kotarbinski, Elenya Grant, Sanjana Vijayshankar, Kaitlin Brunik, Jared Thomas, Abhineet Gupta, Steven Hammond, Vivek Singh, Richard Tusing, Pingping Sun, Kyuha Lee, Amgad Elgowainy, Hanna Breunig, Fabian Rosner, and João Pereira Pinto, "Techno-economic analysis of low-carbon hydrogen production pathways for decarbonizing steel and ammonia production," Cell Reports Sustainability, 2025, forthcoming.

Electrolysis Facility Capex Component	Percent of Total Capex in 2025 ($1,850/kW, 2022$)	Learning Rate (%)	Base Year (2025) In-stalled Capacity (GW)
Symbol	C_o	*LR*	V_o
Stack	24%	11%	3.9
Balance of Plant	13%	13%	23.9
Power Electronics	11%	12%	23.9
Hydrogen Conditioning	5%	7%	23.9
Installation	47%	11%	23.9

Table A2. Learning rate parameters for electrolysis capex as a function of cumulative installed capacity.

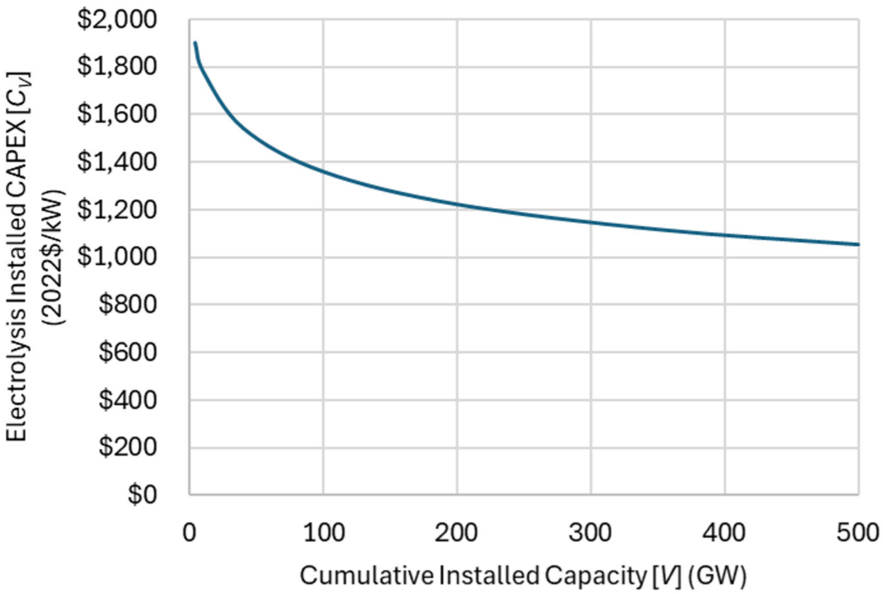

Figure A2. Total installed electrolysis facility capex (2022$/kW) as a function of cumulative installed l capacity (GW).

Appendix 6: Export Analysis Assumptions

- ***Overall assumptions:***
  Labor costs associated with production not scaled by country.

- ***Low-carbon reformation-based hydrogen overall assumptions:***
  assumes new-build ATR facility with CCS, 660 tons per day production capacity, operating at 90% utilization, 94.5% capture rate, and $990M plant+CCS capex; U.S. Texas gas assumptions were based on EIA *Annual Energy Outlook* 2023 reference case regional industrial gas prices used in other figures; Global gas price assumptions were based on McKinsey Energy Solutions 40-year average prices; 2030 gas price assumptions: $2.5/MMBtu (KSA), $3.6/MMBtu (Qatar).

- ***Australia coal gasification scenario:***
  assumes new-build coal gasification plant with CCS, 230 Nm3/h production capacity, operating at 90% utilization, 70% capture rate, $1.4 billion plant+CCS capex, and $0.07/kg coal price; CO_2 transport and storage costs are $23/t CO_2 in 2025 and $20/t CO_2 in 2030.

- ***Electrolysis overall assumptions:***
  assumes 500 MW PEM electrolysis project with 2030 installed capex of $1520/kW, system capex of $389/kW; and storage capex of $41.65/kg capacity and storage opex of $0.10/kg stored / year; assumes same battery capex ($1,436/kWh) and opex (2.5% of capex)—the same configurations as U.S. configurations shown elsewhere in this report; U.S. configurations rely on the West Texas example; Variability across countries is driven by LCOEs (listed below) and WACC (ranged between 10-11.40%, depending on country).

  - ***2030 Australia optimized build mix:*** 1.0-1.3-1.0 solar-wind-electrolyzer ratio, 27% solar capacity factor, 42% wind capacity factor and 75% overall electrolyzer capacity factor, $40/MWh solar LCOE, and $40/MWh wind LCOE; assumes wind co-located with electrolysis and solar sourced through a VPPA.
  - ***2030 Chile optimized build mix:*** 1.1-1.0 wind-electrolyzer ratio, 65% wind capacity factor, 18% solar capacity factor, and 70% overall electrolyzer capacity factor, $26/MWh wind LCOE and $55/MWh solar LCOE; assumes wind co-located with electrolysis.
  - ***2030 Germany optimized build mix:*** 1.1-1.1-1.0 solar-wind-electrolyzer ratio, 11% solar capacity factor, 42% wind capacity factor and 57% overall electrolyzer capacity factor, $78/MWh solar LCOE and $80/MWh wind LCOE; assumes wind co-located with electrolysis and solar sourced through a VPPA.
  - ***2030 Japan optimized build mix:*** 0.3-1.0-1.0 solar-wind-to-electrolyzer ratio, 15% solar capacity factor, 50% wind capacity factor, and 55% overall electrolyzer capacity factor, $99/MWh solar LCOE, and $95/MWh wind LCOE; assumes wind co-located with electrolysis and solar sourced through a VPPA.
  - ***2030 Morocco optimized build mix:*** 1.3-1.0-1.0 solar-wind-electrolyzer ratio, 28% solar capacity factor, 44% wind capacity factor and 71% overall electrolyzer capacity factor, $40/MWh solar LCOE and $55/MWh wind LCOE; assumes solar co-located with electrolysis and wind sourced through a VPPA.
  - ***2030 Spain optimized build mix:*** 0.6-1.1-1.0 solar-wind-electrolyzer ratio, 25% solar capacity factor, 54% wind capacity factor and 71% overall electrolyzer capacity factor, $50/MWh solar LCOE and $46/MWh wind LCOE; assumes wind co-located with electrolysis and solar sourced through a VPPA.

Data Sources: ANL, Hydrogen Delivery Scenario Analysis Model (HDSAM), as of February 2024); EIA, *Annual Energy Outlook* (2023); LevelTen, *PPA Index* as of December 2023; McKinsey Hydrogen Insights, as of February 2024; McKinsey Energy Solutions, H2 Cost Optimization Model (H2-COM); NETL, "Fossil-Based Hydrogen Production Comparison" (April 2022); NREL, *Annual Technology Baseline* (2023); NREL, H2A-Lite Model, as of February 2024

Appendix 7: Assumptions for 2030 Willingness to Pay and Demand Estimates

- ***Overall assumptions:***

  Willingness to Pay (WTP) and demand represent a point in time (2030) and are subject to change.

- ***Drop-in replacements—current applications:***

  These demand estimates assume that clean hydrogen can replace 100% of carbon-intensive hydrogen in their respective markets.

  - **Forklifts**
    - **WTP ($4-10/kg):** Estimates based on offtake agreements for current clean hydrogen-powered forklifts in the United States.
    - **Demand (60 kt):** Based on ~560K forklifts and ~50-60K fuel cell powered forklifts.
  - **Ammonia**
    - **WTP ($0.9-1.2/kg):** Range based on EIA *Annual Energy Outlook* 2023 reference natural gas prices for fossil-based ammonia production; low (Texas) and high (California) natural gas prices.
    - **Demand (3.2 MMT):** ANL 2020 study estimated 3.13 MMT demand in 2024 and 3.6 MMT in demand by 2050; applied a steady-state growth from 2024 to 2030 and assumed hydrogen priced at $2/kg.
  - **Refining**
    - **WTP ($0.8-1.2/kg):** Assumes EIA *AEO* 2023 high (California) and low (Texas) regional industrial natural gas prices.
    - **Demand (7.5 MMT):** Based on ANL 2020 study, hydrogen demand is expected to stay relatively flat in proportion to crude input. This estimate assumes that all domestic hydrogen demand switches to clean hydrogen.
  - **Methanol (chemicals)**
    - **WTP ($0.7-1.0/kg):** Assumes incumbent technology is methanol produced from natural gas without CCS ($340-400/ton Methanol [MeOH]); range includes breakeven point vs. fossil alternative for electrolysis-based or reformation-based hydrogen with industrial carbon capture (priced at $60-70/ton) using a Fischer Tropsch process.
    - **Demand (1.3 MMT):** Assumes 1-3 MMTpa would be required to satisfy the 15-30 MMTpa of MeOH demand in the United States by 2050 (based on International Energy Agency [IEA] and IRENA forecasts) and assuming that half of methanol production uses clean hydrogen and that ~0.19 MT of hydrogen are required to produce 1 MT of methanol.

- ***Additional clean hydrogen market upside—nascent applications:***
  These demand estimates assume that clean hydrogen can service some of these emerging applications, assuming additional technological developments and/or midstream infrastructure buildout.

  - **Trucking**
    - **WTP ($3.6-4.8/kg):** Compares ICE scenario with EIA reference case diesel price; high case assumes CA LCFS credit up to $140/credit through 2032. Also assumes 30% 45W credit on all truck-related expenses and adds $2.1/kg for compressing, (high utilization 700 bar) dispensing, and fueling station costs. This additional $2.1/kg does not include credits for fueling stations from IRA 30C. This range is in line with the range presented in NREL's *Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis* models for zero-emission vehicles (ZEVs) adoption based on economics (cost of driving) using the Transportation Energy & Mobility Pathway Options (TEMPO) model. Modeling showed that fuel cell electric vehicles (FCEVs) were able to achieve significant market penetration when the price of hydrogen reached $4/kg. The same report references an underlying source[36] that suggests FCEV buses may be competitive with diesel at fuel cell costs below $125/kW and hydrogen prices of $5/kg, considering a 5-year financial horizon.
    - **Demand (0.1MMTpa MMT):** Based on NREL's *Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis*, hydrogen demand for HDMD trucks is forecasted to be 0.1 MMT in 2030 and increase to 3.2 MMT by 2040 and 7.8 MMT by 2050; however, this does not incorporate hydrogen consumption to produce other low-carbon fuels.
  - **PtL SAF**
    - **WTP ($1-3.3/kg):** Range based on EIA *AEO* reference oil price for Jet A ($2.7/gal); high case assumes CA LCFS credit up to $140/credit through 2032.
    - **Demand (65 kt):** 65 kt of hydrogen could produce 32.5 million gallons of SAF, which assumes <1% of SAF penetration within total jet fuel demand (30 billion gallons) by 2030. The U.S. may see production capacity of 250 million gallons per year of PtL SAF (750 kt) by 2030, but most of this capacity is expected to be exported as ammonia to the E.U.
  - **Biofuels**
    - **WTP ($0.8-1.8/kg):** Assumes incumbent technology is reformation-based hydrogen without carbon capture for use in biofuels synthesis; assumes EIA *AEO* 2023 high (California) and low (Texas) regional industrial natural gas prices; high case assumes conventional methanol prices increased by 30% and there's an upside from CA LCFS credit up to $140/credit through 2032.
    - **Demand (0.4 MMT):** The June 2023 *U.S. National Clean Hydrogen Strategy and Roadmap* projects approximately 2-6 MMT of clean hydrogen could be required to produce 35 billion gallons of SAF from biofuels in 2050. Estimates based on preliminary analysis from NREL evaluating 10 different feedstocks for hydrogen production. For each feedstock, a range of hydrogen demands per gallon of biofuel was estimated, based on system designs that minimize and maximize hydrogen use to optimize yield. Feedstock evaluated included seed oils; corn grain; forestry resources and woody wastes; woody energy crops; municipal solid waste; agricultural residues; herbaceous energy crops; algae; fats, oils, greases; and wet wastes. The SAF Grand Challenge targets 3 billion of SAF from biofuels by 2030; assuming the same proportion of clean hydrogen required for biofuels generates an estimated clean hydrogen demand of 0.2-0.5 MMT. Relatedly, the IEA estimates domestic demand of 45 billion gallons of diesel by 2030. This estimate assumes that renewable diesel represents ~5% of this demand by 2030 (2 billion gallons) based on operational and planned hydroprocessed esters and fatty acids (HEFA) plants and that 5% of renewable diesel by mass comes from clean hydrogen.

36 Andrew Burke and Anish Kumar Sinha, *Technology, Sustainability, and Marketing of Battery Electric and Hydrogen Fuel Cell Medium-Duty and Heavy-DutyTrucks and Buses in 2020–2040*, National Center for Sustainable Transportation Research Report no. NCST-UCD-RR-20-09 (2020).

- **Maritime fuels**
  - **WTP ($0.8-1.6/kg):** Assumes conventional methanol is sold at $0.38/kg, implying a clean hydrogen price of $0.77/kg MeOH. Range is based on fuel oil from EIA *AEO* oil prices ranges from $10-17/MMBtu and expanded to include *U.S. National Clean Hydrogen Strategy and Roadmap* range for synthetic fuels.
  - **Demand (0.2 MMT):** Assumes 1.8-2 megatons of maritime fuel demand (using e-methanol as the reference case, although the WTP assumes both e-methanol and ammonia).
- **Steel**
  - **WTP (<$1.2/kg):** Value represents the green premium required for green steel to breakeven with traditional Blast Furnace-Basic Oxygen Furnace (BF-BOF) steel, based on *U.S. National Clean Hydrogen Strategy and Roadmap*.
  - **Demand (0.1 MMT):** Minimal expected demand given highly price-dependent; assumes 100 megatons of steel production will utilize 0.1 MMT of clean hydrogen for direct reduced iron (DRI) (accounting for <1% of steel production), assuming that that ~0.1 MT of hydrogen is required to reduce 1 MT of iron ore.[37]
- **Power (H_2 CCGTs)**
  - **WTP ($0.3-0.6/kg):** Range is based on California low oil price scenario (high cost) and Texas high oil price scenario (low cost) for industrial natural gas prices.
  - **Demand (1 MMT):** EIA *AEO* projects 7.97 quads of natural gas demand for the U.S. power sector in 2030; assuming a 5% volume share of clean hydrogen, the total demand for clean hydrogen could total nearly 1 MMT.

Data Sources: ANL, *Demands for Hydrogen* (October 2020); Catherine Redna, et al., *Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis* (NREL, March 2022); DOE, *U.S. National Clean Hydrogen Strategy* & Roadmap (June 2023); DOE, *SAF Grand Challenge Roadmap: Flight Plan for Sustainable Aviation Fuel Report* (September 2022); EIA, *Annual Energy Outlook* (2023); Hydrogen Council, *Path to Hydrogen Competitiveness: A Cost Perspective* (January 2020).

37 ANL, "*Assessment of Potential Future Demands for Hydrogen in the United States*," ANL-20/35 (October 1, 2020).