Review of Projections through 2040 of U.S. Clean Hydrogen Production, Infrastructure, and Costs

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The business of sustainability

ERM

Acknowledgements

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About ERM

ERM provides strategic consulting services to address energy and environmental issues for the private, public, and non-profit sectors. ERM creates value and addresses risks with a comprehensive approach to strategy and implementation, ensuring clients have timely access to information and the tools to use it to their advantage. Our approach fuses private sector strategy with public policy in air quality, energy, climate change, environmental markets, energy efficiency, renewable energy, transportation, and advanced technologies. Our international client base includes electric and natural gas utilities, major transportation fleet operators, investors, clean technology firms, environmental groups, and government agencies. Our seasoned team brings a multi-sector perspective, informed expertise, and creative solutions to each client, capitalizing on extensive experience in energy markets, environmental policy, law, engineering, economics, and business. For more information, we encourage you to visit our website, www.erm.com or www.sustainability.com.

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Acronyms and Abbreviations

Name	Description
45V	United States Code [U.S.C.] § 45V
CAD	Canadian dollar
capex	capital expenditures
CCS	carbon capture and storage
CO_2	carbon dioxide
CO2e	carbon dioxide equivalent
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
EU	European Union
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GW	gigawatt
H2	hydrogen
H2Hubs	Regional Clean Hydrogen Hubs
IRA	Inflation Reduction Act
kg	kilogram
km	kilometer
kw	kilowatt
LDC	local distribution companies
LCOH	Levelized Cost of Hydrogen
OD	outer diameter
opex	operating expenditures
PTC	production tax credits
MMT	million metric ton
MW	megawatt
MWh	megawatt hour
N/A	not available
NOx	nitrogen oxide
PEM	polymer electrolyte membrane
RE	renewable energy
SMR	steam methane reformation
SOEC	solid oxide electrolyzer cell
tpd	tons per day of capacity

INTRODUCTION

In recent years, hydrogen has increasingly been considered a strategy to achieve power sector greenhouse gas (GHG) emissions reductions. To evaluate hydrogen as a viable emissions reduction strategy, ERM undertook this literature review to assess projections of clean hydrogen supply, costs, and infrastructure through 2040, with a focus on the power sector.

The term "clean hydrogen" commonly refers to hydrogen produced by electrolysis with low or no GHG emissions using renewables or nuclear energy, as well as hydrogen produced by steam methane reformation (SMR) with carbon capture and storage (CCS). This review defines clean hydrogen as that produced with less than 0.45 kilograms of carbon dioxide equivalent (CO2e) overall GHG emissions per kilogram of hydrogen (kg CO2e/kg H2) from "well to gate," consistent with the definition of the lowest tier identified for the highest hydrogen production tax credits (PTC) available through the Inflation Reduction Act (IRA) of 2022 (United States Code [U.S.C.] § 45V, hereafter referred to as "45V PTC"). In the studies reviewed for this paper, hydrogen produced by electrolysis meets this GHG emissions criteria, subject to the carbon intensity of the electricity supply. Instances where studies include SMR with CCS along with electrolysis in their definition of clean hydrogen are noted throughout this report. Infrastructure assessed in this report includes dedicated hydrogen pipelines, storage, and customized point-of-use blending infrastructure.

This report includes a summary of findings from the literature review, a summary of evident limitations of the literature, and a discussion of the drivers and challenges to clean hydrogen production and infrastructure build-out. Key findings and limitations are highlighted in the next sections and included in Table 1 and Table 2. Table 1 summarizes findings related to clean hydrogen production and associated costs, with a focus on production via electrolysis and an emphasis on power sector end use where noted. Table 2 summarizes findings related to clean hydrogen infrastructure specific to the power sector, and associated infrastructure costs. As part of this review, ERM also developed an analysis to estimate the costs of clean hydrogen production and delivery as a point of comparison to the available literature. A brief description of the analysis is included in the discussion section and a range of results are included in Table 1 and Table 2.

KEY FINDINGS

The available literature provides various projections of clean hydrogen supply, infrastructure, and associated costs while demonstrating commonalities in key drivers that will shape real-world outcomes through 2040. Highlighted herein are key findings from the literature review.

- **Supply Volumes.** The projected domestic supply of clean hydrogen is influenced by multiple factors including costs, technological improvements, end use demand, geographic constraints, policy and regulatory considerations, and available workforce. Supply projections across all sectors in 2030 ranged from 10 million metric tons (MMT) to 16 MMT, increasing toward 2040 to range from 20 MMT to 30 MMT.
- **Clean Hydrogen Production Costs.** Cost estimates for domestic clean hydrogen production ranged widely across the literature, though it is clear IRA tax credits have a meaningful impact on costs. Additionally, across all studies, costs are projected to decline over time as the market evolves, technology advances, and while IRA PTC remain available. When looking solely at subsidized clean electrolysis production costs, estimates in 2030 ranged from near or below $0 per kilogram (kg) to around $2/kg.

  - Costs are highly dependent on location as electricity supply costs significantly impact resulting clean hydrogen production costs, most notably for electrolysis. Regions with abundant low-cost renewable resources could produce lower-cost clean hydrogen, as illustrated by modeling from Ricks and Jenkins (2023), ERM, and others.

- **Infrastructure.** Delivered costs of hydrogen varied widely depending on infrastructure costs, mode of transport, and storage. The U.S. Department of Energy (DOE) estimated that midstream infrastructure, including compression, storage, and pipeline distribution, represents approximately half of the delivered cost of hydrogen.[1]
  - Pipeline transportation is likely to be more cost-effective compared to trucking for distributing large volumes needed for power generation. DOE projected pipeline costs in 2030 to range from $0.1/kg to $0.50/kg, depending on the capacity and transport distance.
  - At present, the levelized costs for compressed gas storage are four to 10 times higher than that of geologic storage.[2] By 2030, DOE projected these cost differences to persist with estimates of salt cavern storage ranging from $0.05/kg to $0.15/kg and compressed gas storage ranging from $0.80/kg to $1.00/kg.

- **Delivered Hydrogen Costs.** Few estimates exist for delivered hydrogen costs, likely in part due to the high level of variation in hydrogen infrastructure costs (including compression, storage, and pipeline delivery), which currently represents a sizable share of the estimated delivered cost.
  - Cost declines could help with infrastructure scaling. DOE projected the levelized cost of delivered clean hydrogen to drop significantly from $10/kg in 2023 to a range of $0.70 to $1.15/kg in 2030 (assuming subsidized production costs below $0.40/kg by 2030).

Policy and regulatory developments are expected to influence the trajectory of supply and infrastructure build-out. Additionally, further research would be needed; in particular, research that relies on operational data from existing applications in the power sector, to narrow the range of projections and to assess efficiencies that could be gained through electrolyzer improvements and through regionality.

LIMITATIONS

Assumptions and data availability varied widely across the studies reviewed for this report. Some key limitations include:

- *Clean hydrogen definition.* For example, many studies only assessed clean hydrogen produced with electrolyzers powered by zero carbon electricity, while others included hydrogen produced with SMR and CCS in addition to electrolyzers.
- *Power sector focus.* Few studies analyzed supply, costs, and infrastructure for clean hydrogen in the power sector end use specifically, though ERM and others continue to actively assess this potential.
- *Tax credit impacts.* As of the publication of this report (August 2023), guidance for the 45V PTC is not yet available. Though most of the studies reviewed for this report estimated the effect of the 45V PTC on hydrogen production cost, they made varying assumptions of what will qualify for the credit.
- *Electricity supply costs.* Electricity supply costs greatly impact delivered clean hydrogen costs, particularly for electrolyzers, and are a key driver of differing results across studies as well as within a

[1] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), pp. 26, 57.
[2] Ibid, p. 36.

given report. Showing cost ranges helps to capture the impact of differing assumptions, such as to demonstrate regional variability of low-cost zero carbon electricity for clean hydrogen production.

- *Policy and regulatory impacts.* The clean hydrogen economy is evolving and the impacts of some recently announced policies and proposals from the U.S. Environmental Protection Agency (EPA) and DOE directed toward clean hydrogen are not captured in available analyses. Relatedly, it remains to be seen how the build-out of the Regional Clean Hydrogen Hubs (H2Hubs) will influence the availability of clean hydrogen supply since no projects have been officially selected by DOE as of the publication of the report.
- *Time horizon and data granularity.* Not all studies reviewed the same time horizon, and they varied in the granularity of data available from 2030 to 2040.
- *Accounting for inflation.* Studies were not uniform in stating assumptions around inflation and what dollar year costs are denominated. Given publication dates, unless otherwise noted, this report assumes values are in $2022.

These limitations warrant consideration when drawing conclusions or comparing the results across studies. Despite these limitations, the literature reviewed for this report presented several key findings and suggested a variety of drivers influencing clean hydrogen supply and infrastructure forecasts, further discussed in the sections to follow.

DISCUSSION

The projected supply of upstream clean hydrogen production and build-out of midstream infrastructure are influenced by several factors related to costs, technological improvements, end uses, geographic constraints, policy and regulatory considerations, and available workforce. Increasing the scale of clean hydrogen will require a significant build-out of electrolyzer production, zero carbon electricity, and midstream infrastructure. Technological advancements across the clean hydrogen value chain, along with increased demand for clean hydrogen, access to the 45V PTC, and declining electricity costs, can create opportunities to grow cost-effective clean hydrogen supply and infrastructure. Achieving cost reductions prior to the sunset of the 45V PTC in 2033, coupled with closing a potential gap between demand and supply, may help the development of a self-sustaining commercial market for clean hydrogen that is competitive for the power sector and multiple other end uses.[3]

While the assumptions and projections shown in Table 1 and Table 2 vary across studies, there are commonalities in the key drivers that shape the outcomes through 2040. The following discussion highlights the findings from the literature and themes influencing clean hydrogen supply and infrastructure projections.

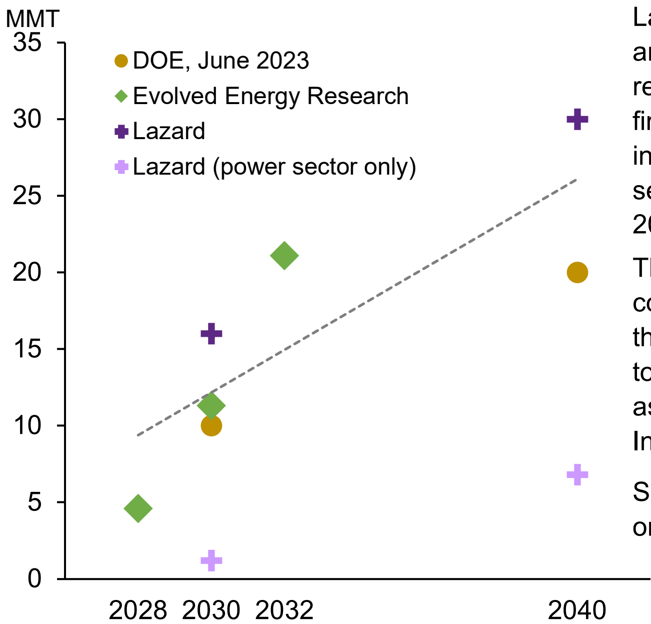
Supply Volumes

Projections for domestic clean hydrogen supply across all sectors in 2030 ranged from 10 MMT to 16 MMT, and for 2040 ranged from 20 MMT to 30 MMT. Figure 1 shows select estimates of U.S. hydrogen supply as available from the literature review, with more information in Table 1.

[3] Ibid, p. 65; Energy Futures Initiative, The U.S. Hydrogen Demand Action Plan (2023).

Most studies reported total supply serving a range of sectors such as power, bulk chemicals, transportation, and industrial end uses. DOE supply estimates were in the middle of the studies reviewed and ranged from 10 MMT in 2030 to 20 MMT in 2040, including clean hydrogen supply produced by electrolysis and by SMR with CCS. DOE estimated that their projections for 2030 could be met if the more than 100 announced clean hydrogen projects are built.[4]

See Table 1 for a summary of findings related to clean hydrogen production, with a focus on production via electrolysis and with an emphasis on power sector end use where noted.



Dashed line reflects trend of total supply projections.

Figure 1: Clean Hydrogen Supply Projections

Lazard (2023) is the only study reviewed that analyzed supply specific to the power sector only, reflecting clean hydrogen blending in natural gas-fired plants. Projections from Lazard (2023) included on Figure 1 estimated supply to the power sector ranging from 1.2 MMT in 2030 to 6.8 MMT in 2040.[5]

The studies agreed that clean hydrogen supply could increase significantly over time with many of the projections in particular anticipating growth due to the build-out of the $7 billion H2Hubs program, as announced by DOE as part of the Bipartisan Infrastructure Law.

See the discussion sections to follow for more detail on these and other key considerations for supply.

Production Costs

Projected costs for clean hydrogen production via electrolysis are dependent on operating expenditures (opex) for electricity supply, capital expenditures (capex) related to the costs of electrolyzers, and the utilization factor of electrolyzers. While all three of these factors will remain important, the availability and cost of clean electricity are key drivers influencing clean hydrogen production costs. See Table 1 for a range of clean hydrogen production costs identified in the literature review and from ERM's analysis further discussed below. Note that studies were not uniform in stating assumptions around inflation and what dollar year costs are denominated. Given publication dates, unless otherwise noted, this report assumes values are in $2022.

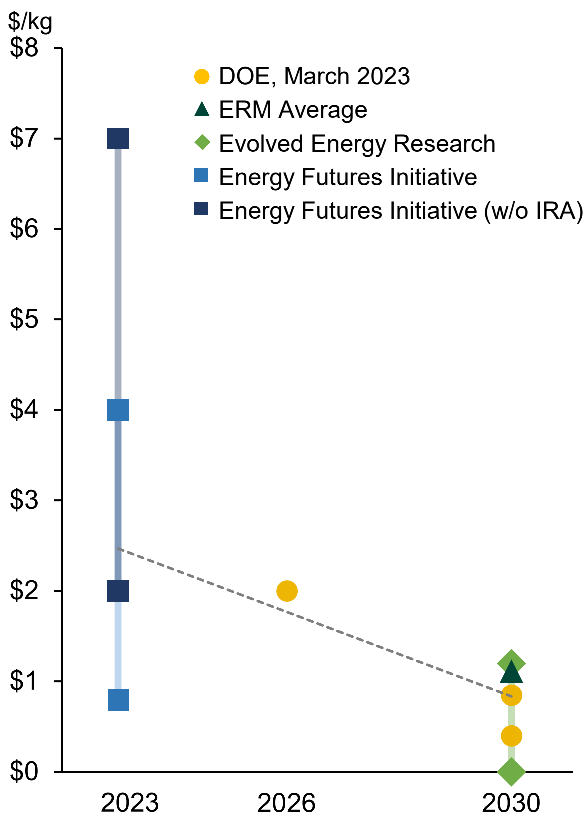
See Table 1 for a summary of findings related to associated costs for clean hydrogen production, with a focus on production via electrolysis and with an emphasis on power sector end use where noted.

[4] DOE, U.S. National Clean Hydrogen Strategy and Roadmap (2023), pp. 15, 20.

[5] Lazard (2023) values for the power sector assume a compound annual growth rate of 30 percent from 2021 to 2040. Supply projections through 2040 include multiple sectors in addition to power generation, including: petroleum refining (7.8 MMT), LDC blending (4.8 MMT), ammonia (3.5 MMT), methanol (2.7 MMT), road transport (1.3 MMT), aviation fuel (1.2 MMT), shipping fuel (1.2 MMT), and steelmaking (0.3 MMT).

While cost estimates ranged widely for production in 2023, the projections converged to below $2/kg, subsidized, by 2030. The range of subsidized levelized cost projections for clean hydrogen production is shown on Figure 2. IRA tax credits have a meaningful impact on costs. Most studies accounted for clean hydrogen qualifying for the full $3/kg ($2020) 45V PTC. Without the tax credits, the Energy Futures Initiative (2023) study estimated 2023 costs to range from $2/kg to more than $7/kg, while inclusion of the tax credits results in costs from near $0/kg up to $4.1/kg. This range represents different production types and variability between U.S. regions.

When looking across the available literature, costs are highly dependent on location as electricity supply costs significantly impact resulting clean hydrogen production costs, most notably for electrolysis. Regions with abundant low-cost renewable resources could produce lower-cost clean hydrogen, as illustrated by modeling from Ricks and Jenkins (2023), which performed a meta-analysis of cost estimates from a number of other studies and found subsidized clean hydrogen production costs could be below $0/kg—as low as low as -$0.58/kg—in regions where clean electricity costs are around $30 per megawatt hour (MWh) or less.[6] Higher production costs are mostly associated with higher clean electricity costs, as well as lower electrolyzer utilization rates. The ERM analysis, as described in more detail below, also aimed to highlight the impact of these different assumptions in its 2030 cost ranges included in Table 1.



Projections include IRA subsidies unless otherwise noted as without (w/o) IRA. Trend line for subsidized costs only.

Figure 2: Subsidized Clean Hydrogen Production Cost Projections

The price of electricity will become more material as capital cost declines are expected to outpace electricity cost declines.[7] The guidance for 45V PTC is expected to influence the supply options and therefore the price of electricity for clean hydrogen producers. Temporality or time matching requirements of the electricity supply relative to clean hydrogen production may also impact the production utilization factors. For example, if renewable resource availability is lower, decreased utilization factors would increase levelized costs, all else being equal.[8] All of these variables, compounded by regional variability, make it challenging to compare and calibrate assumptions across studies but also demonstrate the range of potential scenarios to evaluate.

Across all studies, costs are projected to decline through 2030 as the market evolves, technology advances, and while IRA PTC remain available. When looking solely at electrolysis production costs, estimates in 2030 ranged from near or below $0/kg to around $2/kg. For example, ERM's high cost for 2030 was $2.03/kg, reflecting regions with more expensive delivered electricity and lower electrolyzer utilization. Alternatively, and as noted above, Ricks

[6] Ricks, Wilson, and Jesse Jenkins. The Cost of Clean Hydrogen with Robust Emissions Standards: A Comparison Across Studies. (2023), p. 7.

[7] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), p. 27

[8] Energy Futures Initiative, The U.S. Hydrogen Demand Action Plan (2023), p. 49.

and Jenkins (2023) projected negative costs for some regions, though it is unclear what year these costs reflected.

Demand for electrolyzers and scale of production are factors that will influence capex costs as clean hydrogen production scales from 2030 to 2040. At present, some hydrogen producers are quoted lead times of 2 to 3 years when they order electrolyzers.[9] By 2030, domestic production would need to scale from 4 gigawatts (GW) of publicly announced manufacturing capacity to 20 to 25 GW per year to enable deployment of around 100 GW of operational electrolyzers.[10] While there is no single primary driver for reducing costs, scaling electrolyzer manufacturing and technological innovation would be needed.[11]

To meet growth projections for clean hydrogen production via electrolysis, the availability of raw materials for polymer electrolyte membrane (PEM) electrolyzer manufacturing could become a factor. Large increases in the extraction and refining of iridium could lead to an increase in reliance on foreign suppliers, given there is no significant domestic source of iridium.[12] If catalyst levels for PEM electrolyzers remain at current levels, the U.S. could require up to 30 percent of today's global iridium production to meet supply predictions by 2030.[13] Technological advancements could decrease demand for foreign materials and lead to electrolyzer cost and efficiency improvements.

Electrolyzer Improvements

Most electrolysis currently relies on one of three technologies: PEM, alkaline, or solid oxide electrolyzer cells (SOECs). The alkaline process is the most established technology and is generally best suited for large-scale industrial installations that require a steady hydrogen output at low pressures.[14] PEM systems are increasing in commercial scale-up and can operate effectively at a range of loads and with variable energy sources such as renewables. SOECs are the least commercialized of the technologies and use a ceramic electrolyte at high temperatures creating higher efficiencies than PEM and alkaline.[15]

To meet the growth projections outlined in DOE's Commercial Liftoff report, electrolyzers would need to see 50 percent to 80 percent cost declines by 2030.[16] Industry forecasts projected system capex costs for PEM and alkaline decreasing by 60 percent by 2030, with SOEC capex costs decreasing 80 percent in the same timeframe.[17] This could bring the range of system capex costs for all three electrolyzer technologies from $760 per kilowatt (kW) to $2,500/kW down to $230/kW to $500/kW.[18] Innovative system designs such as increasing the electrolyzer module size, increasing stack production to automated production, improving electrolyzer lifetimes, monetizing co-generated oxygen, and accessing waste heat could lead to system and cost efficiencies that could translate to increased potential for hydrogen production via electrolysis.[19] Improving electrolyzer system efficiency could also lead to cost improvements; however, declining costs for renewables would have a greater relative impact on overall production costs.[20]

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[9] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), p. 46.
[10] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), pp. 35, 46.
[11] DOE, U.S. National Clean Hydrogen Strategy and Roadmap (2023), pp. 41–42.
[12] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), pp. 45–46, 59; International Journal of Hydrogen Energy (2021).
[13] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), pp. 59.
[14] Lazard, Levelized Cost of Energy+ (2023), pp. 25.
[15] DOE, U.S. National Clean Hydrogen Strategy and Roadmap (2023), pp. 40.
[16] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), pp. 13, 66.
[17] Hydrogen Council, Path to Hydrogen Competitiveness: A Cost Perspective (2020).
[18] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), p. 13.
[19] International Renewable Energy Agency (IRENA), Green Hydrogen Cost Reduction – Scaling Up Electrolysers to Meet the 1.5 Degree C Climate Goal, 2020; DOE, U.S. National Clean Hydrogen Strategy and Roadmap (2023), p. 42.
[20] DOE, U.S. National Clean Hydrogen Strategy and Roadmap (2023), p. 42.

ERM Analysis

As a point of comparison to the available literature, and to explore how assumptions impact results, ERM developed an analysis to estimate the cost of clean hydrogen production and delivery. To better reflect available information, ERM made assumptions that would align with other studies' assessments of how the clean hydrogen industry may evolve over time, including clean electricity supply. For key inputs such as a range of costs for production technology, electricity, storage, and transportation, as well as other key assumptions such as utilization factors, ERM relied on publicly available data and industry expertise. This included key cost projections informed by the U.S. Energy Information Administration Annual Energy Outlook and information found throughout the literature review, in particular DOE reports.

The range of cost results from the ERM analysis included in Table 1 and Table 2 aims to show the impact of electricity supply costs and other utilization factors. The resulting ranges help illuminate the impact of differing assumptions and also reflect likely regional variability of low-cost zero carbon electricity for clean hydrogen production. The lower end of the ERM analysis cost ranges assumed higher utilization factors (90 percent) and lower electricity supply costs ($35/MWh), thus representing regions with high renewable resource potentials, and assumed more localized production with lower-end costs for clean hydrogen transportation and storage. The higher end of the cost ranges assumed the opposite—lower utilization (55 percent), higher electricity supply costs ($60/MWh), and greater midstream costs (included in delivered cost estimates in Table 2, as Table 1 reflects production cost estimates only).

The average of the clean hydrogen production cost ranges from the ERM analysis is included on Figure 1 above and is similar to 2030 costs found in other studies. See Table 1 and Table 2 for more information on the ERM analysis results and assumptions.

Scaling Delivery and Storage Infrastructure

See Table 2 for costs and estimates associated with clean hydrogen infrastructure identified in the literature review and further discussion herein, with a focus on blending technology, storage, and pipeline transportation needs.

> See Table 2 for a summary of findings related to clean hydrogen infrastructure specific to the power sector, and associated infrastructure costs.

When producing clean hydrogen for the power sector, specific technical considerations related to co-firing hydrogen in natural gas combined cycle turbines should be addressed. Plant operators must consider factors such as differences in hydrogen and natural gas physical and combustion properties, nitrogen oxide (NOx) emissions mitigation, and changes to the turbines and balance of plant to handle greater quantities of hydrogen.[21] While most existing gas turbines today can blend hydrogen up to about 5 percent, new turbines on the market are able to burn about 15 percent to 100 percent hydrogen.[22] Depending on the level of hydrogen blending, retrofitting an existing gas turbine could cost up to $25 million for a 100 megawatt (MW) plant mainly to cover upgrades to offload, process, and pipe hydrogen through the plant.[23] Additionally, multiple private companies have announced commercially ready turbines that can be fired on hydrogen and natural gas blends with a path to 100 percent hydrogen combustion.[24]

[21] Energy Futures Initiative, U.S. Hydrogen Demand Action Plan (2023), p. 61; DOE, U.S. National Clean Hydrogen Strategy and Roadmap (2023), p. 35.
[22] Energy Futures Initiative, U.S. Hydrogen Demand Action Plan (2023), p. 61.
[23] National Renewable Energy Laboratory, Annual Technology Baseline (2022); Öberg, Simon, Mikael Odenberger, and Filip Johnsson. Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems; International Journal of Hydrogen Energy 47.1 (2022): 624–644. Assumes 25 percent base capex to retrofit facility and $1,000/kW base capex for initial natural gas plant.
[24] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), p. 30.

Infrastructure estimates and projections range from 2022 to 2030, with no predictions found in the literature beyond 2030. In their delivered cost projections, DOE estimated that midstream infrastructure, including compression, storage, and pipeline distribution, represents approximately half of the delivered cost of hydrogen.[25] DOE estimated that $85 billion to $215 billion of cumulative investment is required to scale the domestic clean hydrogen economy through 2030, with as much as half of the investment required for midstream or end-use infrastructure, and another third for net new clean energy production for electrolysis. This range was driven by DOE's variation in demand scenarios, with the upper bound of demand scenarios predicting twice as much clean hydrogen demand in 2030 as the lower bound demand scenario.[26]

The costs of hydrogen infrastructure vary widely depending on the mode of transport. Hydrogen currently remains relatively costly to distribute and store,[27] and several factors would need to be considered for scaling clean hydrogen infrastructure into the 2030s and beyond. In situations where co-locating production and end use is not viable, there currently is limited availability of midstream infrastructure for scaling clean hydrogen. At present in the U.S., there are about 1,600 miles of dedicated hydrogen pipelines, compared to more than 300,000 miles of natural gas transmission pipelines.[28] Due to the time needed for permitting and construction and the nascency of the hydrogen economy, DOE projects that new hydrogen pipelines will likely remain limited until at least the late 2020s.[29] Looking to Europe as a point of comparison for hydrogen pipeline infrastructure projections, a European energy network consortium is planning for over 14,500 miles of dedicated hydrogen pipeline across five supply corridor projects in 2030.[30] Hydrogen pipelines are preferable to trucking for distribution at large volumes needed for power generation, though there is uncertainty with pipeline construction costs for longer transport distances.[31] As detailed in Table 2, DOE projected hydrogen pipeline costs in 2030 to range from $0.1/kg to $0.50/kg, depending on the capacity and transport distance.

As of 2021, there are three salt caverns for hydrogen storage in operation in the U.S.[32] DOE viewed additional salt cavern geologic storage as a critical anchor for commercial viability, while noting limited geographic availability, with about 2,000 salt caverns concentrated in specific regions of North America.[33] Compressed gas is another storage option. There can be challenges related to scale when serving power generation larger than a small standby generator or a cogeneration facility. At present, the levelized costs for compressed gas storage are four to 10 times higher than that of geologic storage.[34] By 2030, DOE projected these cost differences to persist with estimates of salt cavern storage ranging from $0.05/kg to $0.15/kg and compressed gas storage ranging from $0.80/kg to $1.00/kg, as detailed in Table 2.

DOE noted that significant pipeline infrastructure will likely not be needed until about 2030 when offtake scales up.[35] After 2030, DOE projected midstream investment requirements will ramp-up from $2 to $3 billion per year to $15 to $20 billion per year from 2030 to 2050. Factors driving demand for infrastructure included more distributed end uses adopting clean hydrogen, and linking local hubs and regional networks into a national hydrogen distribution network.[36] Co-locating nuclear generation or renewables

[25] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), pp. 26, 57.
[26] Ibid, p. 42. Investment needs are in $2020.
[27] Ibid, p. 71.
[28] Congressional Research Service, Pipeline Transportation of Hydrogen: Regulation, Research, and Policy (2021), p. 5.
[29] Ibid, p. 50.
[30] European Hydrogen Backbone. Five hydrogen supply corridors for Europe in 2030. (2022), pp. 22, 47, 72, 97, 121.
[31] International Journal of Hydrogen Energy (2022).
[32] Satyapal, S., Testimony of Dr. Sunita Satyapal Director for a Hearing on Hydrogen, U.S. Senate Energy and Natural Resources Committee (2022).
[33] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), p. 17.
[34] Ibid, p. 36.
[35] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), p.14.
[36] Ibid, p. 44.

with storage near end uses can reduce the need for infrastructure build-out, helping to reduce costs.[37] The selection and future completion of the regional H2Hubs can offer opportunities to build from lessons learned and to better understand the regional differences in potential clean hydrogen end uses and generation sources to maximize clean hydrogen production.

Delivered Hydrogen Costs

Few estimates exist for delivered hydrogen costs, likely in part due to the high level of variation in hydrogen infrastructure costs (including compression, storage, and pipeline delivery), which currently represent a sizable share of the estimated delivered cost. DOE projected the levelized cost of delivered clean hydrogen to drop significantly from $10/kg in 2023 to a range of $0.70 to $1.15/kg in 2030 (assuming subsidized production costs of less than $0.40/kg by 2030),[38] which could help to scale infrastructure beyond 2030. ERM estimated costs for delivered hydrogen as a point of comparison to DOE. Beginning with the cost ranges for production included in Table 1. ERM then accounted for storage, pipeline transportation, and delivery of clean hydrogen to an end-user, estimating delivered costs in 2030 to range from $0.88 to $2.74/kg (see Table 2).

Policy and Regulatory Considerations

Policy and regulatory developments related to clean hydrogen are expected to influence the trajectory of supply and infrastructure build-out. Notably, the Bipartisan Infrastructure Law of 2021 directs $9.5 billion to the DOE for clean hydrogen, including $7 billion for the development of six to ten H2Hubs that will create networks of hydrogen producers, consumers, and local connective infrastructure to accelerate the use of clean hydrogen.[39] In July 2023, DOE announced a $1 billion investment into a new demand-side initiative to support the H2Hubs intended to help provide market certainty.[40] In addition, IRA of 2022 contains additional incentives for clean hydrogen, including the 45V PTC discussed above in the production costs section, and extensions and expansions of credits for clean electricity investment and production that can help to drive down the costs of clean hydrogen production.[41] Specific to the power sector, in May 2023, the EPA proposed standards to limit carbon dioxide emissions from fossil fuel-fired power plants, including hydrogen co-firing at natural gas-fired units, as a proposed best system of emission reduction.[42]

Most of the studies reviewed included the effect of the 45V PTC and discussed the influence that H2Hubs could have on the future of clean hydrogen production and infrastructure. However, the impact of policies and proposals announced in 2023 such as the DOE's demand-side initiative and EPA's proposed power plant emissions standards are not captured in available analyses. Ultimately, the impact of most of these recent policy and regulatory developments remains to be seen, but they help send a market signal and offer some stability to support the growth of a clean hydrogen economy.

Permitting

Local and federal permitting requirements for siting new generation, transmission, and clean hydrogen infrastructure can vary widely throughout the country. The patchwork of authorities and the anticipated evolving regulatory architecture for clean hydrogen infrastructure as new interstate projects take shape

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[37] Ibid, p. 36.
[38] Assuming electrolysis production costs of less than $0.40/kg by 2030 with $3/kg PTC applied.
[39] DOE, Regional Clean Hydrogen Hubs (n.d.).
[40] DOE, Biden-Harris Administration to Jumpstart Clean Hydrogen Economy with New Initiative to Provide Market Certainty And Unlock Private Investment (2023).
[41] *Inflation Reduction Act of 2022,* Public Law 117-169, *U.S. Statutes at Large 136(2022): 1818-2090*.
[42] EPA, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants (2023).

risk holding back capital flows or challenging electrolysis scale-up.[43] Each part of the hydrogen value chain is regulated by various federal entities whose authorities are under consideration in light of recent permitting reform discussions. Permitting authorities may ultimately include the EPA, the Federal Energy Regulatory Commission (FERC), the Bureau of Safety and Environmental Enforcement, and the Pipeline and Hazardous Materials Safety Administration, among others.[44] Breaking ground on new hydrogen pipelines is projected to take time due to both the nascency of the hydrogen economy and long construction and permitting timelines.[45] In some instances, new responsibilities may need to be granted for permitting authority.[46] The H2Hubs could offer an opportunity to assess permitting authorities and support lessons learned for expediting the review process for future deployments.[47]

Workforce Development

The projected supply of clean hydrogen and build-out of midstream infrastructure will be influenced by the availability of a specialized hydrogen workforce. Although there is some similarity in skills from adjacent industries, the workforce must scale quickly to accommodate the engineering, operations, and construction skills needed to manufacture and operate hydrogen infrastructure. DOE estimated the hydrogen economy can create about 100,000 net new direct and indirect jobs related to new clean hydrogen infrastructure build-out in 2030, with an additional nearly 120,000 direct and indirect jobs in 2030 related to the operations and maintenance of hydrogen assets. The availability of trained workforce could impact the scale at which the hydrogen economy can grow from 2030 to 2040.[48]

CONCLUSION

The projected supply of clean hydrogen production and build-out of infrastructure are influenced by several factors related to costs, technological improvements, end uses, geographic constraints, policy and regulatory considerations, and available workforce. Technological advancements across the clean hydrogen value chain, along with increased demand for clean hydrogen, policy and regulatory developments, and declining electricity costs can create opportunities to grow a self-sustaining commercial market for clean hydrogen that is competitive for the power sector and multiple other end uses.

The available literature provided various projections on clean hydrogen supply, infrastructure, and associated costs while demonstrating commonalities in key drivers that will shape real-world outcomes through 2040. Additional research as clean hydrogen is utilized more in the power sector will increase data availability and provide lessons learned; in particular, as regional H2Hubs are deployed, more information on the associated costs, infrastructure, production, workforce, permitting, and challenges resulting from these investments would help to assess projections and efficiencies that can be gained through regionality and experiences in power supply.

[43] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), p.64.
[44] Sandia National Laboratories, Federal Oversight of Hydrogen Systems (2021), p. 17; U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration Guidance (2023).
[45] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), p. 50.
[46] Energy Futures Initiative, U.S. Hydrogen Demand Action Plan (2023), p. 83.
[47] DOE, U.S. National Clean Hydrogen Strategy and Roadmap (2023), p. 25.
[48] DOE, Pathways to Commercial Liftoff: Clean Hydrogen (2023), pp. 44, 48, 71.

TABLES

Table 1: Clean Hydrogen Production Projections (2023–2040)

Year	Volume (MMT per year)	Costs incl. IRA Credits ($/kg) [a]	Costs excl. IRA Credits ($/kg) [a]	Region	Hydrogen Production Pathway [b]	Key Assumptions	Source
2023	N/A	$0.80/kg to $4.00/kg	$2.00/kg to $7.00/kg	U.S.	SMR+CCS, clean power electrolyzer	Average cost based on today's energy cost data for nine different U.S. regions. The low end of the range represents regions with abundant renewable energy potential and low-cost carbon dioxide storage. Renewables available for purchase at **$26/MWh**, in addition to electrolyzers at 40 to 45% utilization.	Energy Futures Initiative, 2023, p. 12
	N/A	$1.2/kg	$4.2/kg	Texas	Nuclear with electrolyzer	Industrial electricity prices at **$73/MWh**; electrolyzer at 90% utilization.	Energy Futures Initiative, 2023, pp. 50–51
	N/A	$4.1/kg	$7.1/kg	Washington	RE with electrolyzer	RE costs at **$67/MWh**; electrolyzer at 19% utilization.	
	N/A	$0/kg	$3/kg	Texas	RE with electrolyzer	RE costs at **$26/MWh**; electrolyzer at 45% utilization.	
2026	N/A	$2.00/kg	N/A	U.S.	N/A	Assumes LCOH based on announced unit costs.	DOE, March 2023, p. 69
2028	4.6 MMT	N/A	N/A	U.S.	RE with electrolyzer	Projected supply for "economic demand" scenario includes power, bulk chemicals, transportation, and industry end uses. Assumes declining electrolyzer costs and onshore solar and wind renewable build-out that slows down over time. For power sector, assumes blending in new and existing gas plants up to 7% by energy content (approximately 20% by volume).	Evolved Energy Research, 2023, p. 15
2030	N/A	< $0.40/kg	N/A	U.S.	RE electrolyzer	Based on varying RE and technology costs; assumes qualification for $3/kg credit from 45V PTC.	DOE, March 2023, pp. 22, 26
	N/A	$0.40/kg to $0.85/kg	N/A	U.S.	SMR+CCS	Assumes qualification for $0.75/kg credit from 45V PTC.	

Year	Volume (MMT per year)	Costs incl. IRA Credits ($/kg) [a]	Costs excl. IRA Credits ($/kg) [a]	Region	Hydrogen Production Pathway [b]	Key Assumptions	Source
	10 MMT	N/A	N/A	U.S.	SMR+CCS, RE with electrolyzer	Set target to meet 10 MMT/year with end uses split across industries and new demand; 200 GW of new RE needed by 2030 to support. All currently announced H2 projects would have to be built to meet this demand.	DOE, June 2023, pp. 15, 20
	11.3 MMT	$0.00/kg to $1.20/kg	N/A	U.S.	RE with electrolyzer	Cost reflects marginal cost. See assumptions above in 2028 for Evolved Energy Research (2023).	Evolved Energy Research, 2023, pp. 15
	16 MMT for all end uses; 1.2 MMT for power sector only	See below for costs with no year		U.S.	Electrolyzers	PEM electrolyzer (20 to 100 MW). Model does not consider development costs of the electrolyzer and associated RE facility, conversion, storage and transportation of the H2 once produced, costs to upgrade existing infrastructure, electrical grid upgrades, or costs associated with modifying end-use infrastructure and equipment to use the fuel.	Lazard, 2023, pp. 26, 27
	N/A	$0.42/kg to $2.03/kg	N/A	U.S.	RE with electrolyzer	ERM relied on publicly available data and industry expertise. Key cost projections informed by the U.S. Energy Information Administration Annual Energy Outlook and information found throughout the literature review, including DOE reports. Cost range reflects utilization factors of 55% (higher cost) to 90% (lower cost); electricity costs of **$35 to 60/MWh**.	ERM Analysis
	N/A	$0.83/kg to $1.18/kg (45V PTC only)	N/A	U.S.	SMR+CCS, 90% capture		
2032	21.1 MMT	N/A	N/A	U.S.	RE with electrolyzer	See assumptions above in 2028 for Evolved Energy Research (2023).	Evolved Energy Research, 2023, pp. 15
2040	20 MMT	N/A	N/A	U.S.	SMR+CCS, RE with electrolyzer	Set target to meet 20 MMT/year with end uses split across power, industry, and transportation. For energy storage/power, assumes threshold price (willingness to pay) of approximately $1/kg with varying thresholds for	DOE, June 2023, pp. 18, 20

Year	Volume (MMT per year)	Costs incl. IRA Credits ($/kg) [a]	Costs excl. IRA Credits ($/kg) [a]	Region	Hydrogen Production Pathway [b]	Key Assumptions	Source
						other sectors. Willingness to pay reflects the total price of H2 available to end user, including cost of production, distribution, and additional conditioning onsite, such as compression, storage, and dispensing.	
	30 MMT for all end uses; 6.8 MMT for power sector only	See below for costs with no year		U.S.	Electrolyzers	See assumptions above in 2030 for Lazard (2023).	Lazard, 2023, pp. 26, 27
N/A	See above by year	$1.68/kg to $4.28/kg	$4.77/kg to $7.37/kg	U.S.	RE with electrolyzer	See assumptions above in 2030 for Lazard (2023).	Lazard, 2023, pp. 26, 27
		$1.16/kg to $2.99/kg	$3.47/kg to $5.29/kg	U.S.	Nuclear with electrolyzer		
	N/A	$2.54/kg	N/A	U.S.	Solar with electrolyzer	Based on Rhodium Group (2023) report. Assumes electricity cost of **$23/MWh**; electrolyzer at 26% utilization.	Ricks and Jenkins, 2023, pp. 7
	N/A	$0.69/kg	N/A	Northern California	Solar with electrolyzer and batteries	Based on Ricks et al. (2023) report. Assumes electricity cost **$24 to 41/MWh**; electrolyzer at 71% utilization.	
	N/A	$1.18/kg	N/A	Arizona	Solar with electrolyzer	Based on Wood Mackenzie (2023) report. Assumes electricity cost of **$34/MWh**; electrolyzer at 46% utilization.	
	N/A	$(0.16)/kg	N/A	Pacific Northwest	RE with electrolyzer	Based on Ricks et al. (2023) report. Assumes electricity cost **$24 to 41/MWh**; electrolyzer at 92% utilization.	

Year	Volume (MMT per year)	Costs incl. IRA Credits ($/kg) [a]	Costs excl. IRA Credits ($/kg) [a]	Region	Hydrogen Production Pathway [b]	Key Assumptions	Source
	N/A	$(0.58)/kg	N/A	Texas, Minnesota	RE with electrolyzer	Based on Energy Innovation LLC (2023) report. Assumes electricity cost **$16 to 27/MWh**; electrolyzer at 85% utilization.	
	N/A	$0.19/kg	N/A	Texas	RE with electrolyzer	Based on Wood Mackenzie (2023) report. Assumes electricity cost of **$32/MWh**; electrolyzer at 72% utilization.	
	N/A	$1.16/kg	N/A	Texas	Wind with electrolyzer	Based on Energy Futures Initiative (2023) report. Assumes electricity cost of **$26/MWh**; electrolyzer at 40% utilization.	
	N/A	$0.46/kg	N/A	Florida	RE with electrolyzer	Based on Cybulsky et al. (2023) report. Assumes electricity cost of **$41/MWh**; electrolyzer at 81% utilization.	
	N/A	$(0.27)/kg	N/A	Texas	RE with electrolyzer	Based on Cybulsky et al. (2023) report. Assumes electricity cost of **$27/MWh**, electrolyzer at 83% utilization.	

45V PTC = hydrogen production tax credits available through the Inflation Reduction Act (IRA) of 2022 ; CCS = carbon capture and storage; DOE = U.S. Department of Energy; GW = gigawatt; H2 = hydrogen; IRA = Inflation Reduction Act; kg = kilogram; LCOH = Levelized Cost of Hydrogen; MMT = million metric ton; MW = megawatt; MWh = megawatt hour; N/A = not available; PEM = polymer electrolyte membrane; RE = renewable energy; SMR = steam methane reformation

[a] Studies were not uniform in stating assumptions around inflation and what dollar year costs are denominated. Given publication dates, unless otherwise noted, this report assumes values are in in $2022.

[b] RE means renewable energy. In most cases, this includes onshore wind and utility-scale solar.

Table 2: Clean Hydrogen Infrastructure Projections (2022–2030)

Infrastructure Type	Year	Costs ($/kg) [a]	Capacity/ Distance	Region	Key Assumptions	Source
LCOH, delivered to customer	**2023**	$10.00/kg	N/A	U.S.	Based on reported current costs from stakeholders. Distribution and storage can more than double delivered cost. Exact conditioning, storage, and transport costs are highly dependent on volume, distance, storage time, and methods used.	DOE, March 2023, pp. 57
	2030	$0.70/kg to $1.15/kg	N/A	U.S.	Assumes electrolytic production costs of <$0.40/kg, with $3/kg 45V PTC applied. Mean to account for full value chain, including compression, storage, and pipeline distribution.	DOE, March 2023, pp. 22, 26
		$0.88/kg to $2.74/kg	N/A	U.S.	ERM relied on publicly available data and industry expertise. Key cost projections informed by the U.S. Energy Information Administration Annual Energy Outlook and information found throughout the literature review, including DOE reports. Cost range reflects utilization factors of 55% (higher cost) to 90% (lower cost); electricity costs of **$35 to 60/MWh**; midstream pipeline transport costs $0.25 to 0.50/kg with storage costs approximately $0.25/kg.	ERM Analysis
Gas compression	**2030**	$0.10/kg	80 to 120 bar, 50+ tpd	U.S.	Based on cost shared from leading-edge companies who have deployed at demonstration scale or larger. Assumes pipeline, co-located electrolysis.	DOE, March 2023, pp. 26
Salt cavern storage	**2030**	$0.05/kg to 0.15/kg	600 tpd at 80 bar for 7 days	U.S.	Based on cost shared from leading-edge companies who have deployed at demonstration scale or larger. Salt cavern storage allows for large-scale storage at low capex costs, though limited availability (approximately 2,000 salt caverns in North America with an average capacity of 10^5 to 10^6 m^3).	DOE, March 2023, pp. 17
Compressed gas tank storage	**2030**	$0.80/kg to $1.00/kg	950 kg stored at 500 bar with 1 cycle/ week	U.S.	Levelized cost, does not include compression. Highest unit cost option for storage, but lower capex due to smaller scale. Storage capex costs assumed to decline over time to approximately $400/kg in 2030.	DOE, March 2023, pp. 17
Hydrogen pipeline	**2022**	$0.66/kg for 1,000 km;	607 tpd	Canada	Levelized cost dominated by pipeline costs (70%), with electricity costs making up 8%. Considers long-distance, high-capacity hydrogen pipelines.	Int. Journal of Hydrogen

Infrastructure Type	Year	Costs ($/kg) [a]	Capacity/ Distance	Region	Key Assumptions	Source
		$1.98/kg for 3,000 km (2020 CAD)				Energy, 2022, fig. 4
	2030	$0.1/kg	600 tpd, 300 km, 12" OD Approximately 5,000 tpd, 1,000 km, 42" OD	U.S.	Based on cost shared from leading-edge companies who have deployed at demonstration scale or larger.	DOE, March 2023, pp. 26
		$0.20/kg to $0.50/kg	50+ tpd	U.S.	Assumes lowest levelized cost (including compression) at high volumes (50+ tpd) and long distances due to low opex costs, but not commonly used for lower volumes.	DOE, March 2023, pp. 15
		N/A	Low thousands in milage	U.S.	Clean hydrogen milestone for pipeline infrastructure development reflect investment needed to meet 10 MMT/year of demand.	DOE, March 2023, pp. 69
Blending infrastructure	**2022**	$25 million for a 100 MW gas plant, depending on the blending level	N/A	EU	Cost includes retrofitting a turbine to accommodate hydrogen blending. Most of the cost is for power plant upgrades to offload, process, and pipe hydrogen through the plant. Assumes 25% base capex to retrofit facility and $1,000/kW base capex for initial natural gas-fired plant.	DOE, March 2023, pp. 30

CAD = Canadian dollar; capex = capital expenditures; EU = European Union; kg = kilogram; km = kilometer; kw = kilowatt; LCOH = Levelized Cost of Hydrogen; m^3 = cubic meters; MW = megawatt; N/A = not applicable; OD = outer diameter; opex = operating expenditures; 45V PTC = hydrogen production tax credits available through the IRA of 2022 ; tpd = tons per day of capacity

[a] Studies were not uniform in stating assumptions around inflation and what dollar year costs are denominated. Given publication dates, unless otherwise noted, this report assumes values are in in $2022.

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