U.S. DEPARTMENT OF ENERGY

Pathways to Commercial Liftoff: Clean Hydrogen

March | 2023

Comments

The Department of Energy welcomes input and feedback on the contents of this Pathway to Commercial Liftoff. Please direct all inquiries and input to liftoff@hq.doe.gov. Input and feedback should not include business sensitive information, trade secrets, proprietary, or otherwise confidential information. Please note that input and feedback provided is subject to the Freedom of Information Act.

Authors

Authors of the Clean Hydrogen Pathway to Commercial Liftoff:

Office of Technology Transitions: Hannah Murdoch

Office of Clean Energy Demonstrations: Jason Munster

Hydrogen & Fuel Cell Technologies Office: Sunita Satyapal, Neha Rustagi

Argonne National Laboratory: Amgad Elgowainy

National Renewable Energy Laboratory: Michael Penev

Cross-cutting Department of Energy leadership for the Pathways to Commercial Liftoff effort:

Office of Clean Energy Demonstrations: David Crane, Kelly Cummins, Melissa Klembara

Office of Technology Transitions: Vanessa Chan, Lucia Tian

Loan Programs Office: Jigar Shah, Jonah Wagner

Acknowledgements

The authors would like to acknowledge analytical support from Argonne National Laboratory and McKinsey & Company; as well as valuable guidance and input provided during the preparation of this Pathway to Commercial Liftoff from:

Office of Clean Energy Demonstrations: Katrina Pielli, Catherine Clark, Jill Capotosto, Todd Shrader, Sarma Kovvali, Eric Miller, Andrew Dawson

Office of Technology Transitions: Stephen Hendrickson, Katheryn (Kate) Scott, Marcos Gonzales Harsha, James Fritz, Edward Rios

Loan Programs Office: Ramsey Fahs, Julie Kozeracki, Ed Davis, Dinesh Mehta, Monique Fridell, Mike Reed, Christopher Creed

Office of Policy: Carla Frisch, Steve Capanna, Betony Jones, Elke Hodson, Colin Cunliff, Andrew Foss, Paul Donohoo-Vallett, Chikara Onda, Marie Fiori

Hydrogen & Fuel Cell Technologies Office: Eric Miller, Jesse Adam, Dimitrios Papageorgopoulos, Ned Stetson, Brian Hunter, McKenzie Hubert

Office of Energy Efficiency and Renewable Energy: Alejandro Moreno, Paul Spitsen, Avi Shultz, Becca Jones-Albertus, Michael Berube, Brian Cunningham, Carolyn Snyder, Jay Fitzgerald, Ian Rowe

Office of Fossil Energy and Carbon Management: Brad Crabtree, Jen Wilcox, Noah Deich, Mark Ackiewicz, David Alleman, Tim Reinhardt, Robert Schrecengost, Eva Rodezno

Director of the Office of Economic Impact and Diversity: Shalanda Baker, Tony Reames, James Strange

Advanced Research Projects Agency-Energy: Jack Lewnard, James Zahler

Office of International Affairs: Julie Cerqueira, Matt Manning

Office of the General Counsel: Alexandra Klass, Avi Zevin, Narayan Subramanian, Brian Lally, Glen Drysdale

Office of the Chief Financial Officer: Sean James

Assistant Secretary for Congressional & Intergovernmental Affairs: Becca Ward

Acknowledgements (cont.)

Office of Indian Energy Policy and Programs: Wahleah Johns, Albert Petrasek

Office of Federal Energy Management Programs: Mary Sotos, Nichole Liebov

Advanced Manufacturing Office: Isaac Chan, Paul Syers, Felicia Lucci, Nick Lalena, Emmeline Kao

Office of Nuclear Energy: Katy Huff, Alice Caponiti, Jason Marcinkoski, Alison Hahn

Assistant Secretary for Electricity: Michael Pesin

Office of Science: Harriet Kung, Andy Schwartz, Linda Horton, Chris Fecko, Raul Miranda

Solar Energy Technologies Office: Garret Nilsen

Science & Energy Tech Teams (SETT): Rachel Pierson, Kelly Visconti

Argonne National Lab: Aymeric Rousseau

National Renewable Energy Laboratory: Matteo Muratori, Catherine Ledna, Ling Tao

Table of Contents

Purpose of this Report

These Pathways to Commercial Liftoff reports aim to establish a common fact base and ongoing dialogue with the private sector around the path to commercial liftoff for critical clean energy technologies. Their goal is to catalyze more rapid and coordinated action across the full technology value chain.

Executive Summary

The U.S. clean hydrogen market is poised for rapid growth, accelerated by Hydrogen Hub funding, multiple tax credits under the Inflation Reduction Act (IRA) including the hydrogen production tax credit (PTC), DOE's Hydrogen Shot, and decarbonization goals across the public and private sectors.[1,i] Hydrogen can play a role in decarbonizing up to 25% of global energy-related CO2 emissions, particularly in industrial/chemicals uses and heavy-duty transportation sectors.[ii] **Achieving commercial liftoff will enable clean hydrogen to play a critical role in the Nation's decarbonization strategy.**

The clean hydrogen market will be accelerated by historic commitments to America's clean energy economy, including equities in the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA). Together, these supply-side incentives can make clean hydrogen cost-competitive with incumbent technologies in the next 3–5 years for numerous applications.[2] Hydrogen deployment is an opportunity to provide benefits to communities across America, including quality jobs, climate benefits, and decreased air pollution. As with all new technologies, significant care and attention must be paid during implementation to ensure deployment does not perpetuate existing inequities within the energy system.

Clean hydrogen production for domestic demand has the potential to scale from < 1 million metric ton per year (MMTpa) to ~10 MMTpa in 2030.[iii] Most near-term demand will come from transitioning existing end-uses away from the current ~10 MMTpa of carbon-intensive hydrogen production capacity.

If water electrolysis dominates as the production method, up to 200 GW of new renewable energy sources would be needed by 2030 to support clean hydrogen production.[3] The opportunity for clean hydrogen in the U.S., aligned with the DOE National Clean Hydrogen Strategy and Roadmap, is 50 MMTpa by 2050.[4,iii]

Scaling the market will require continuing work on addressing demand-side challenges. For example, scaling midstream infrastructure will drastically lower the delivered cost of hydrogen outside of co-located production and offtake, improving the business case for projects and accelerating uptake of clean hydrogen. Bolstering demand and unlocking long-term offtake will support the current proliferation of hydrogen production project announcements and help those production projects reach final investment decision (FID).

1 Defined as having a carbon intensity < 4 kg CO2e/kg H2
2 See Chapters 2 and 3 for examination of breakeven timing for end uses switching from an incumbent technology to clean hydrogen. Note, breakeven for best-in-class projects does not indicate all projects switching to clean hydrogen would see breakeven in the next 3 – 5 years (see Figures 15 and 27 – Modeling Appendices) for evaluate of best-in-class projects vs. a range of projects.
3 Assumes equal split of solar and wind GW of installed capacity. Capacity factors are based on NREL Annual Technology Baseline Class 5 onshore wind (45%) and utility solar (27%). Range includes PEM and alkaline electrolyzer efficiency from NREL Hydrogen Analysis (H2A) production model. 200 GW represents a high case in which more than 90% of domestic clean hydrogen produced in 2030 is via water electrolysis. Clean power for electrolysis could also come from sources such as nuclear.
4 Equivalent to ~1/10 current domestic natural gas consumption

In the present policy environment, commercial 'liftoff' for clean hydrogen is expected to take place in three phases:

- **Near-term expansion (~2023–2026):** Accelerated by the PTC, clean hydrogen replaces today's carbon-intensive hydrogen, primarily in industrials/chemicals use cases including ammonia production and oil refining.[5] This shift will primarily occur at co-located production/demand sites or in industrial clusters with pre-existing hydrogen infrastructure. In parallel, first-of-a-kind (FOAK) projects are expected to break ground, driven by $8B in DOE funding for Regional Clean Hydrogen Hubs that will advance new networks of shared hydrogen infrastructure.

- **Industrial scaling (~2027–2034):** Hydrogen production costs will continue to fall, driven by economies of scale and R&D. During this period, privately funded hydrogen infrastructure projects will come online. These investments, including the build-out of midstream distribution and storage networks, will connect a greater number of producers and offtakers, reducing delivered cost and driving clean hydrogen adoption in new sectors (e.g., fuel-cell based transport). At the same time, hydrogen combustion or fuel cells for power could be needed to achieve the Administration's goal of 100% clean power by 2035.[6] There are a wide range of forecasts denoting hydrogen's role in the power sector, whether for high-capacity firm, lower-capacity factor power, or seasonal energy storage – see report for more detailed scenarios.

- **Long-term growth (~2035+):** A self-sustaining commercial market post-PTC expiration will be driven by falling delivered costs due to:[7]

  A. Availability of low-cost, clean electricity (for electrolysis),

  B. Equipment cost declines,

  C. Reliable and at-scale hydrogen storage, and

  D. High utilization of distribution infrastructure, including dedicated pipelines that move hydrogen from low-cost production regions to demand clusters.[8]

To achieve profitability post-PTC expiration, cost declines are required over the next 10–15 years. Due to hydrogen's myriad end uses, capex/opex breakeven will be different depending on end use. Today to 2030, industry expects to see significant cost-downs in electrolyzer capex (e.g., ~$760 - 1000/kW today to forecasted $230–400/kW by 2030 for uninstalled alkaline electrolyzers, from $975–1,200/kW to ~$380-450/kW for uninstalled PEM electrolyzers). Low-cost clean hydrogen via electrolysis will also depend on ample availability of low-cost clean electricity (<$20/MWh) that will need to scale in parallel with market demand for clean hydrogen.[9,10] These cost declines translate to a reduction in hydrogen production costs, excluding the PTC, from $3–6/kg today to $1.50–2/kg by 2035. These 2035 expected cost-downs are slightly above the DOE's Hydrogen Shot, which sets an ambitious $1/kg by 2031 target based on stretch R&D goals. Depending on type of electrolyzer and availability of high-capacity factor clean energy, some projects may hit the Hydrogen Shot target ($1/kg without PTC in 2031), which would further accelerate liftoff.

Cost declines for hydrogen delivery will also be critical for transportation end-uses that use hydrogen directly, such as fuel cell powered vehicles.

5 Produced with carbon intensity < 4 kg CO_2e/kg H_2
6 In addition, some private sector plans to co-fire turbines with hydrogen have already been announced
7 See Chapter 3
8 This report refers to hydrogen "distribution" to mean the movement of hydrogen molecules, regardless of scale or mode of movement.
9 Based on forecasts from the Bloomberg New Energy Finance & Hydrogen Council for alkaline electrolyzers. Additional assumptions details are included in the appendix. Quoted numbers are for system capex excluding installation costs.
10 Note that cost-downs are dependent on more than these factors alone – see Chapters 2 and 3 for detail on cost drivers

Project and adoption risk will fall as the clean hydrogen value chain matures. Addressing the commercialization challenges below will unlock each subsequent phase of growth:

- **Near-term expansion:** The cost of midstream infrastructure will be highly relevant for use cases where supply and demand are not co-located.[11] Absence of long-term offtake contracts to manage volume/price risk, uncertainty about cost/performance at scale, permitting challenges, and heterogeneous business models could delay financing for FOAK projects.[12] Electrolyzer supply chains, CO2 distribution and storage infrastructure, and a skilled hydrogen workforce will all face pressure to scale.

- **Industrial scaling:** If not resolved earlier, the growth challenges faced above will be exacerbated during industrial scaling. The pace of clean electricity deployment will be a key driver of hydrogen production technology mix. If constrained, reformation with carbon capture and storage (CCS) is expected to dominate (making up to 80% of hydrogen produced in 2050 versus 50% in a high-renewables scenario).[13]

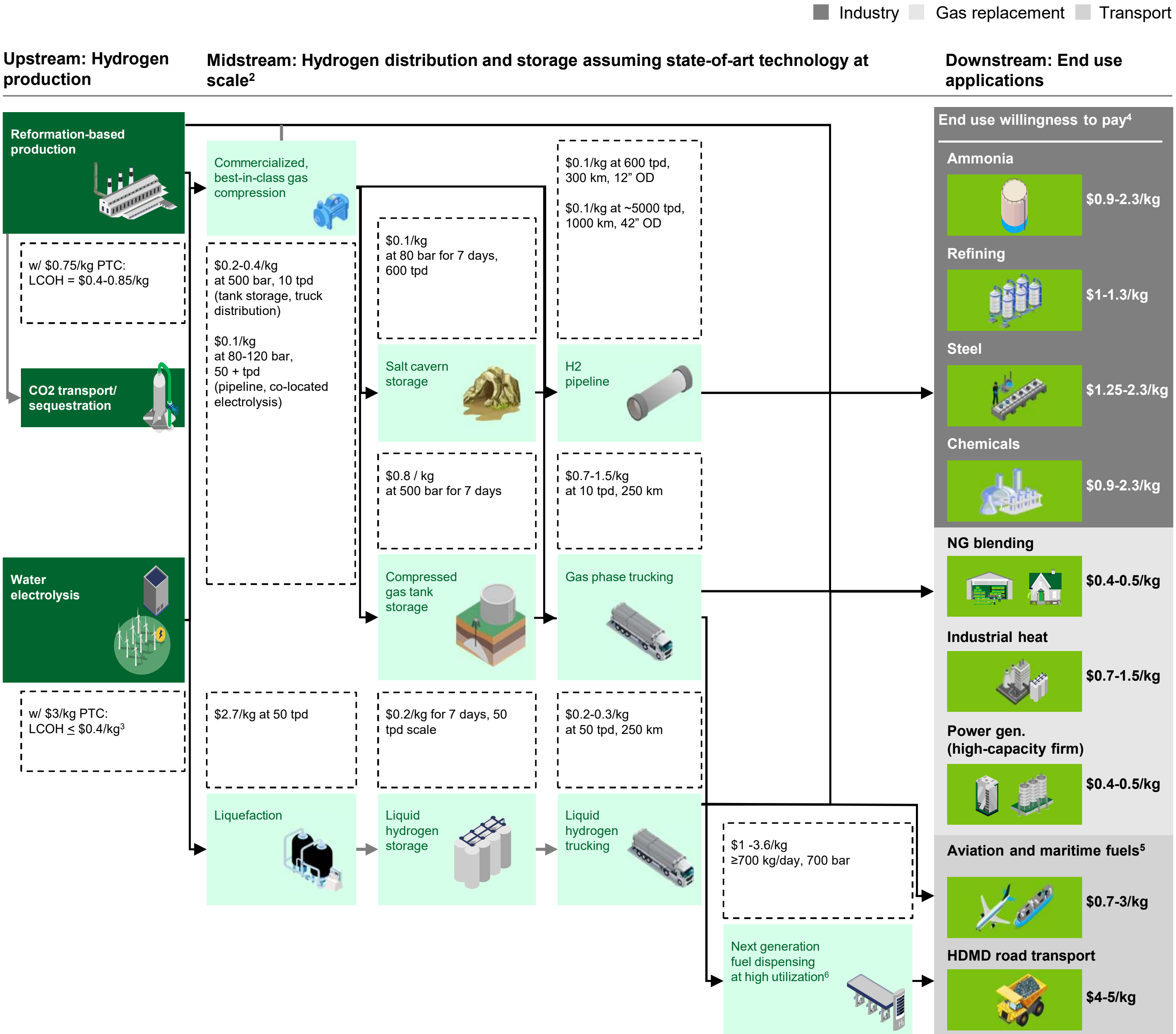
  For water electrolysis, availability of clean electricity and bottlenecks in electrolyzer components/raw materials will play a critical role in the pace of growth. If electrolysis projects fail to scale during the IRA credit period, electrolysis may not achieve the necessary learning curves to remain competitive in the absence of tax credits.

  Each sector converting to clean hydrogen will also have its own opportunities and challenges. For example, fuel cell heavy-duty truck adoption will be highly dependent on the build-out of refueling infrastructure, advancements in fuel cell vehicle technology, certainty of hydrogen supply, and the cost of alternatives (e.g., diesel, battery electric vehicles and their associated costs of charging infrastructure) and regulatory drivers. On the financing side, perceived credit risk will be high for hydrogen projects while these challenges remain unresolved, delaying timelines for low-cost capital providers to enter the market.

- **Long-term growth:** Post-PTC expiration, competitiveness will rely on production and distribution cost declines achieved through the IRA credit period. Development of mature financial structures and contract mechanisms to mitigate the remaining risks (e.g., price volatility) and crowd-in institutional capital will also be needed.[14]

11 Midstream infrastructure can more than double the delivered cost of hydrogen; the U.S. Gulf Coast and parts of California are the only regions with existing H2 networks
12 See Section 3b and 4a.
13 McKinsey Power Model, see Figure 14
14 While not explored in this document, other policy mechanisms will play an important role in meeting 2050 GHG goals (e.g., carbon-intensity standards that would value low-carbon commodities, zero emission vehicle mandates). These initiatives would further bolster the case for clean hydrogen and its derived products, even if not explicitly targeting the clean hydrogen economy.

2030 costs across the value chain if advances in distribution and storage technology are commercialized[1]



1 See appendix for calculation details
2 Data based on cost-downs shared from leading-edge companies who have deployed at demonstration scale (or larger)
3 Range based on varying renewables costs and electrolyzer sizes/technologies
4 Defined as the price an offtaker will pay for clean hydrogen
5 Represents delivery of hydrogen to aviation and maritime fuel production facilities
6 Greater than or equal to 70% utilization, assumes line fill at high pressure
Sources: HDSAM, Argonne National Laboratory; DOE National Hydrogen Strategy and Roadmap, Hydrogen Council

See Figure 10 in body of report: Industry estimates that multiple methods of hydrogen distribution and storage can become affordable if state-of-the-art technologies are commercialized at scale (2030 costs across the value chain). Hydrogen production costs shown take an upper bound of production costs (~2MW (450 Nm3/h) PEM electrolyzer with Class 9 NREL ATB wind power) and then subtract the PTC at point-in-time. See additional notes on Figure 10 to describe credit applications and production costs as well as Figures 11/12 for production costs across different pathways.

Cross-cutting solutions, including DOE H2Hubs, will accelerate market uptake:

1. **Invest in the development of hydrogen distribution and storage infrastructure,** initially through centralized hubs and later through distributed infrastructure. Dispersed infrastructure will unlock use cases for hydrogen where production/offtake are not co-located, connecting new offtakers to regional hydrogen networks. Pipelines and salt-cavern storage will be critical anchors to this system, providing low-cost distribution and storage at scale. As clean hydrogen production scales, cost-effective distribution/storage infrastructure will be essential to avoid bottlenecks in the hydrogen economy. By 2030, half of the necessary clean hydrogen investment dollars are expected to be for midstream and end-use infrastructure ($45–130B).[15]

2. **Catalyze supply chain investments**, including in domestic electrolyzer manufacturing, recycling, and raw materials/components for electrolyzer production.[16] Domestic electrolyzer manufacturing must scale from <1 GW today to up to 20–25 GW/year by 2030.[17] The deployment of adjacent clean energy technologies will also be critical to the hydrogen value chain: up to 200 GW of new renewable energy may be needed by 2030 to produce ~10 MMT clean hydrogen if water electrolysis dominates as the production pathway (>90% production mix) as well as 2–20 million metric tonnes of new CO_2 storage for reformation-based production.[v,18,19,20]

3. **Develop regulations for a scaled industry**, including methods of lifecycle emissions analysis across feedstocks and production pathways.[21] These policy and regulatory developments, along with many others (e.g., changes that would streamline project permitting/siting), would take place across both federal and state agencies and would provide critical certainty to accelerate private investment.

4. **Standardize processes and systems across the hydrogen economy**. Private sector standards organizations will play a critical role in driving cross-industry standard operating procedures (SOPs), certifications, and component interoperability (e.g., at refueling stations) to accelerate project development and reduce costs. Standards can help establish industry-wide safety and environmental protocols.

5. **Accelerate technical innovation through R&D**, including in critical technologies for nascent electrolyzer stacks (e.g., new designs and materials for anion-exchange membrane [AEM] electrolyzers) to bring down costs and mitigate risks of bottlenecks in some electrolyzer technologies (e.g., platinum group metals [PGMs] for proton-exchange membrane [PEM] electrolyzers). R&D is also needed to bring down the cost of carbon capture, utilization, and storage (for reformation-based production) as well as in end-use applications such as improving fuel cell durability.

6. **Expand the hydrogen workforce** with the engagement of companies that have preexisting expertise in safe hydrogen handling (e.g., industrial gas, chemicals, oil and natural gas) as well as labor unions with the skilled workforce and relevant training programs to rapidly expand the workforce. In 2030, third party analysis suggests that the hydrogen economy could create ~100,000 net new direct and indirect jobs related to the build-out of new capital projects and new clean hydrogen infrastructure (~450,000 cumulative job-years through 2030). Direct jobs include employment in fields such as engineering and construction. Indirect jobs include roles in industrial-scale manufacturing and the raw materials supply chain. An additional ~120,000 direct and indirect jobs related to the operations and maintenance of hydrogen assets could also be created in 2030 – these would not all be net new jobs due to the broader transition to a net zero economy, for example, current gas station operators transitioning into hydrogen refueling station operators.[22,23]

15 Based on the Hydrogen Council required investment methodology using the "Net zero 2050 – high RE" demand scenario
16 Raw Materials include platinum group metals (PGMs), such as iridium, which is required for proton exchange membrane (PEM) electrolyzers
17 20 – 25 GW represents an upper bound assuming >90% of clean hydrogen production through 2030 is via water electrolysis and that the electrolyzers used in this production are exclusively from domestic production. See Methodology 13 in Modeling Appendix for details related to this scenario.
18 The U.S. currently stores 25 million metric tonnes CO_2 per year economy-wide, Global CCS Institute, public announcements as of March 2022
19 Range is based on the Net Zero 2050 – high RE and Net Zero 2050 – low RE scenarios, 70-90% capture rates, 8-11 kg CO_2e/kg H_2 pre-capture carbon intensity, and 2 kg CO_2e/kg H_2 upstream methane emissions
20 Up to 200 GW of new renewable energy would be needed if electrolysis dominated (>90% penetration) as the production pathway by 2030. Assumes equal split of solar and wind installed capacity. Capacity factors are based on NREL ATB Class 5 onshore wind (45%) and utility solar (27%). Range includes PEM and alkaline electrolyzer efficiency from NREL Hydrogen Analysis (H2A) production model.
21 Scaled industry implies market growth in line with the projected uptake of clean hydrogen outlined in the DOE National Clean Hydrogen Strategy and Roadmap
22 Inclusive of jobs related to feedstock production, hydrogen production, midstream transportation and storage, and end-use applications.
23 Vivid Economics modeling. See Modeling Appendix for methodology details.

To overcome the above challenges, cross-cutting solutions are required.

7. **Expand and accelerate the capital base,** including mechanisms that manage price and volume risk (e.g., price discovery via a hydrogen commodity market, hedging contracts) and encourage long-term offtake. Shifting from bilateral contracts to a commodity market could lower the cost of capital by reducing counterparty risk but the transition from bilateral agreements would require significantly increased coordination between investors and project developers across the value chain. Underwriting expertise for hydrogen projects also needs to be developed within capital providers' organizations to accelerate the pace of capital deployment. An investment gap of $85–215B remains through 2030. This need for rapid scaling of the capital base means these additional investments and diligence capabilities will be needed to accelerate development, particularly to enable investment in hydrogen distribution, storage, and end-use applications.[24]

The Department of Energy, in partnership with other federal agencies, has tools to address these challenges and is committed to working with communities, labor unions, and the private sector to build the nation's hydrogen infrastructure in a way that meets the country's climate, economic, good jobs, and environmental justice imperatives.

Chapter 1: Introduction and Objectives

Liftoff Reports describe the market structure, current challenges, and potential solutions for the commercialization of interdependent clean energy technologies.[25] Liftoff Reports are an on-going, DOE-led effort to engage directly with energy communities and the private sector across the entire clean-energy landscape.[26] Reports will be updated regularly as living documents and are based on best-available information at time of publication.

This report focuses on deployment considerations that would support a rapid scale-up of the hydrogen value chain—10 MMTpa of clean hydrogen by 2030 and 50 MMTpa by 2050 for domestic demand.[iii] It includes the business models and technologies that could be deployed and the capital that will be required. In particular, this report:

- Focuses on technologies currently in demonstration phase and beyond but otherwise is technology- and business-model agnostic
- Accounts for some of the potential impacts of recent legislation, including the Inflation Reduction Act and the Infrastructure Investment and Jobs Act. It also contextualizes DOE targets such as the Hydrogen 1-1-1 Energy Earthshot™ initiative and builds on both the Draft DOE National Clean Hydrogen Strategy and Roadmap, and extensive H2@Scale analyses
- Highlights key employment and environmental justice factors related to scaling clean hydrogen [27]

24 See Chapter 3 for more detailed description of investment gaps across the hydrogen economy
25 These reports are informed by stakeholder interviews and industry conferences during Q3 and Q4 2022, review of existing publications, and additional analysis/modeling – some via DOE, National Labs, and others by 3rd party sources. Please see Acknowledgements section and Chapter 6 – Modeling Appendices for a comprehensive list of the parties involved.
26 Including, but not limited to - original equipment manufacturers (OEMs) producers, midstream developers, offtakers, investors, community stakeholders, policy leaders, and technical innovators
27 Outlined in Chapter 3.c

Readers should note that, just as in any rapidly evolving industry, figures and numbers in this report will evolve based on additional learnings from researchers and industry, points of regulatory clarity (as released), and more. As such, this report should be viewed as a living, work-in-progress document that will be updated at a regular cadence.

Within upstream production, this report predominantly focuses on:

- **Reformation-based production** with carbon capture and storage (CCS)
- **Water electrolysis** via alkaline and proton exchange membrane (PEM) electrolyzers

Within midstream distribution and storage, this report explores:

- **Conditioning,** including gas-compression and liquefaction
- **Storage,** including salt cavern, compressed gas tank, and liquid hydrogen storage
- **Distribution,** including dedicated pipelines, gas-phase trucking, liquid-hydrogen trucking, and fuel dispensing

Within downstream/end-use sectors, this report evaluates clean hydrogen's potential for uptake across a variety of applications including:

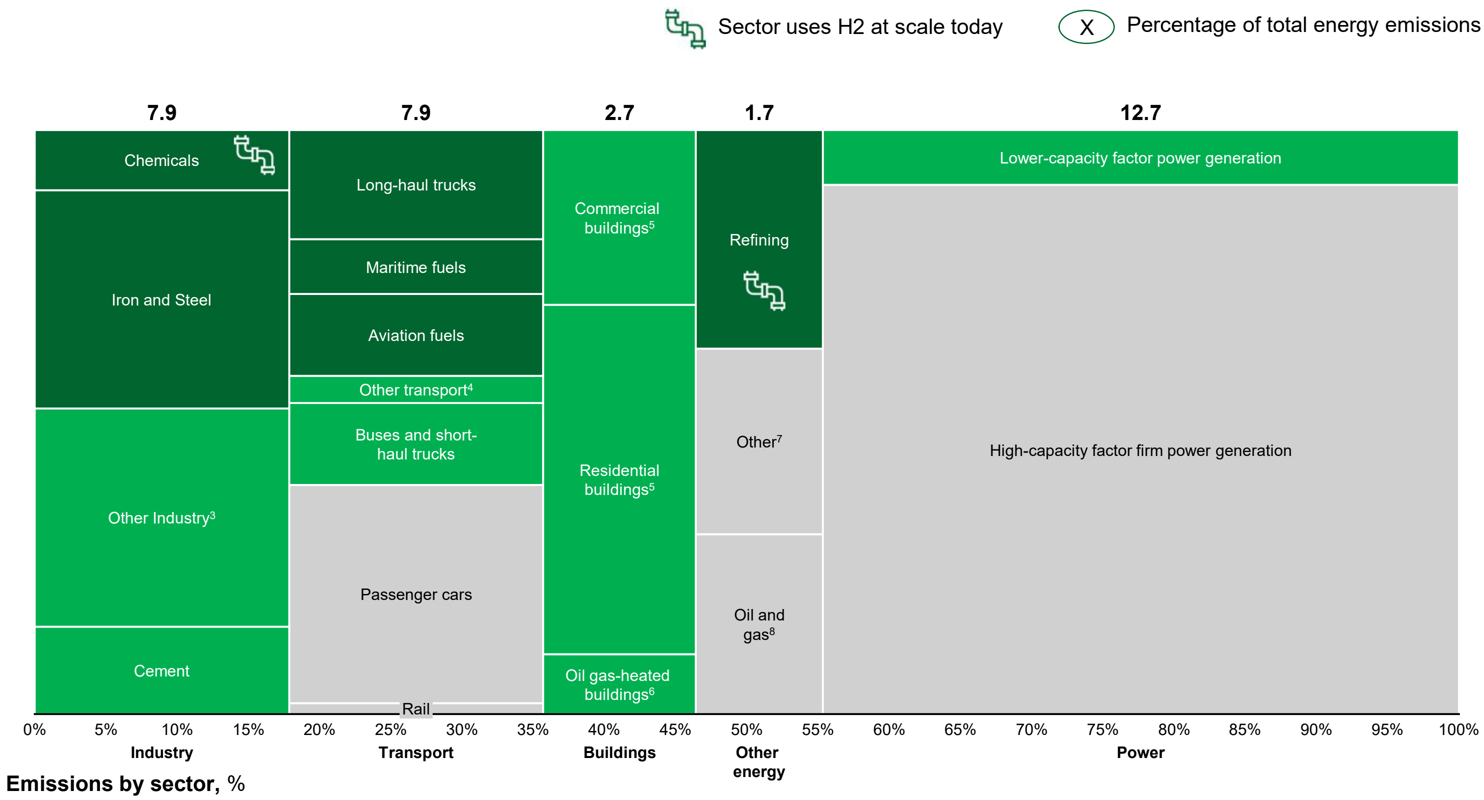
- **Industrials:** Ammonia, refining, chemicals (methanol), and steel
- **Transport:** Heavy-duty and medium-duty road transportation; maritime fuels; aviation fuels
- **Gas replacement:** High-capacity firm power; Lower-capacity factor power; industrial heat; applications for natural gas blending; long-duration energy storage (seasonal)

As challenges to commercial lift-off are overcome, clean hydrogen will play an important role in decarbonizing the U.S. economy, particularly for sectors with few decarbonization alternatives. By 2050, clean hydrogen could reduce overall U.S. CO2e emissions by 10% versus 2005 baseline levels.[iii] Most of the total emissions reduction is expected in heavy-duty transportation (e.g., road, aviation fuels, maritime fuels) and industrial sectors where hydrogen is one of the primary feedstocks (e.g., ammonia, methanol, fuels) and alternatives do not exist. To realize these emissions reductions, cross-sector cost reductions, mechanisms to streamline permitting, safety protocols, monitoring, and handling to avoid leakage are required.[vi]

The U.S. has the opportunity to lead in the production, safe handling and distribution, and responsible end-use of clean hydrogen as it scales globally. Figure 1 illustrates that up to 10–25% of global energy-related carbon emissions are from sectors with a strong potential to adopt clean hydrogen (i.e., hydrogen with a carbon intensity <4 kg CO2e/kg H2). Another 25-40% of total emissions have some potential to decarbonize with hydrogen (e.g., cement, buses, lower-capacity factor power generation).[28]

28 Hydrogen can decarbonize the process heat required for cement manufacturing

Global energy related CO2 emissions in 2019, GT CO2



Strong potential – few alternatives to decarbonize without H2[1]

10-25%[9]

Some potential – H2 can contribute to decarbonization[2]

25-40%

Low potential – hosts few competitive H2 applications

50%

1 Hydrogen is one of few decarbonization options and is likely to be adopted on a large scale if decarbonization is pursued
2 Hydrogen is one of several decarbonization options and adoption will likely be on a limited scale
3 Includes agriculture/forestry, construction, fishing, food and tobacco, manufacturing, mining, nonenergy use, nonferrous metals, and other materials
4 Includes light commercial vehicles (LCVs) and two- and three-wheeled vehicles (e.g., motorcycles)
5 Represents H2-based heat for commercial and residential buildings
6 Old buildings with an existing gas network connection may require adaption of the home heating equipment (e.g., boilers) to convert to H2-based heat
7 Includes transformation processes (e.g., hydrogen and synthetic fuels production)
8 Includes energy use related to oil and gas extraction
9 Low end of range represents hydrogen playing a role only in Chemicals, Long-haul trucks, and refining decarbonization, high end of range represents all sectors listed as "strong potential"
Source: Emissions data and segmentation from McKinsey Energy Insights Global Energy Perspective 2021 and IEA World Energy Outlook 2021, prioritization based on National Clean Hydrogen Strategy and Roadmap

Figure 1: Hydrogen is a multi-faceted decarbonization solution that has a strong potential to play a role in decarbonizing 10–25% of global CO2 emissions in sectors with the fewest other decarbonization options.

Note that cost-effective deployment of clean hydrogen will also depend on the parallel scale-up of other clean energy technologies (e.g., point source carbon capture and sequestration for reformation-based pathways)—**see other Liftoff reports for more on those technologies.**

Chapter 2: Current State – Technologies and Markets

Section 2.a: Technology landscape

Key takeaways

There are three parts to the hydrogen value chain: (1) Upstream production, (2) Midstream distribution and storage, and (3) Downstream use –

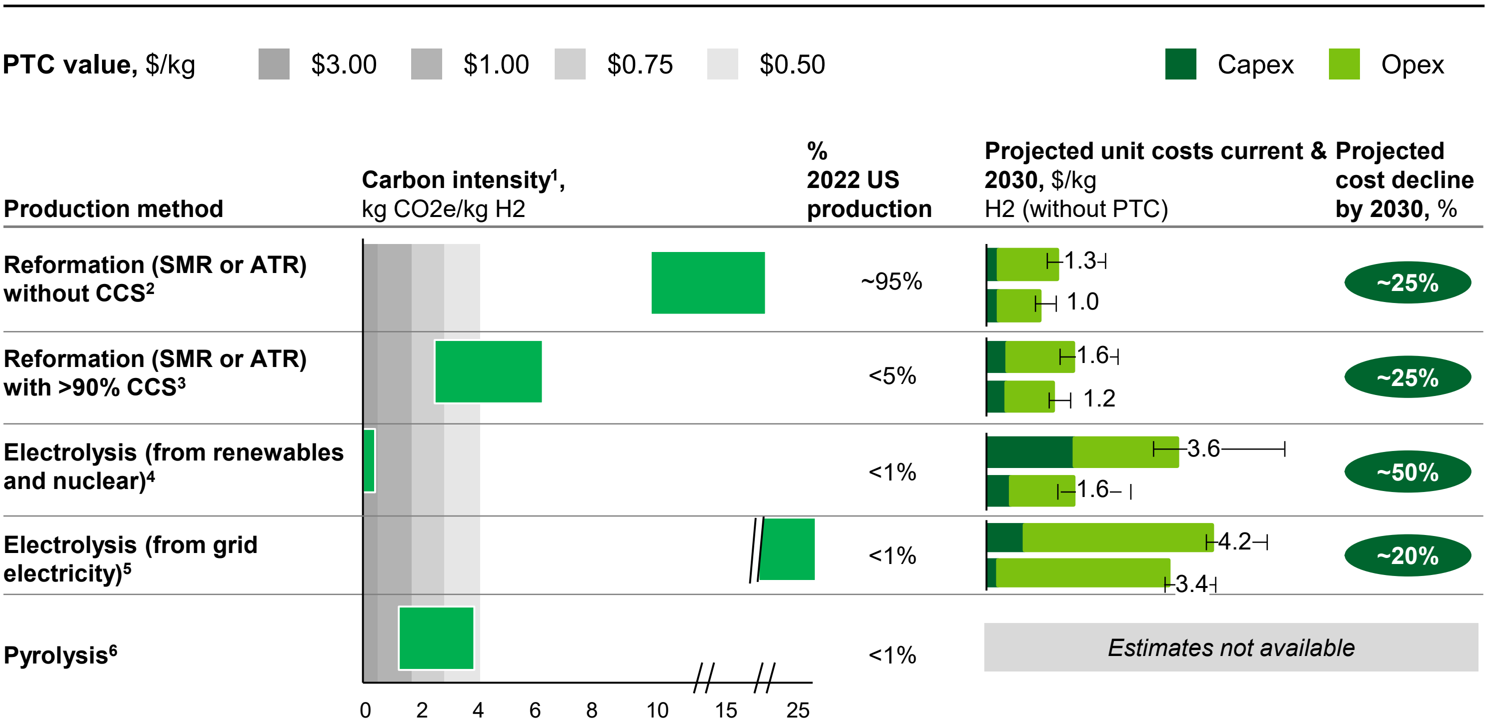
- **Upstream:** Multiple pathways exist to produce clean hydrogen with varying carbon intensity, cost, and maturity. These include reformation with carbon capture and sequestration (CCS) and water electrolysis (Figures 2, 3).
- **Midstream:** There is no single, optimal hydrogen delivery solution for every production schedule, distance/volume transported, and set of end-use requirements. Offtakers that are not co-located with producers or connected via a pipeline must evaluate the cost-effectiveness of gaseous vs. liquid trucked hydrogen for their particular use case, and the extent to which open-access pipelines will be available in the medium-term (Figures 4, 5, 6).
- **Downstream:** Hydrogen can decarbonize a wide range of sectors, particularly for use cases where decarbonization alternatives are costly or impractical. By 2030, most demand for low carbon hydrogen is likely to be as a drop-in replacement for carbon-intensive hydrogen currently used in ammonia and oil refining. Sectors where hydrogen is not an incumbent technology, such as other industrial sectors (steel, chemicals), transportation, heat, and power, will take more time to uptake clean hydrogen (Figure 7). Downstream sectors evaluated for low carbon-intensity hydrogen include:
    - **Industrials:** Ammonia, refining, chemicals (methanol), and steel
    - **Transport:** Heavy-duty and medium-duty road transportation; maritime fuels; aviation fuels
    - **Gas replacement:** High-capacity factor firm power; lower-capacity factor power; industrial heat; applications for natural gas blending; long duration energy storage (seasonal)

There are three parts to the hydrogen value chain: (1) Upstream production, (2) Midstream distribution and storage, and (3) Downstream use.

Upstream: Clean hydrogen production

Multiple pathways exist to produce hydrogen with varying carbon intensity, cost, and maturity. Currently, most domestic hydrogen is produced through carbon-intensive reformation-based approaches without carbon capture (Figure 2).

Comparison of domestic hydrogen production pathways



1 Excludes renewable natural gas feedstocks that would result in negative carbon intensities. Carbon intensities shown are well-to-gate
2 Capex: SMR facility capex (100k Nm3/h capacity): $215 million (current and 2030); reference case natural gas: $4.8/MMBtu (current), $3/MMBtu (2030); high case natural gas: $4.8/MMBtu (current), $3.3/MMBtu (2030); high case based on EIA Advanced Energy Outlook 2022 high oil price scenario. Range for current reformation costs based on +/- 25% natural gas price.
3 Unit costs assumptions are the same as (1), plus CCS capex (for 100k Nm3 / h SMR facility): $145 million (current), $135 million (2030). Currently operational projects with CCS may have lower than 90% capture rates. Negative values not shown but feasible with high percentages of RNG.
4 Assumes alkaline electrolyzer with installed capex: $1400/kW (current, 2MW electrolyzer, 450 Nm3/h), $425 / kW (2030, ~90MW electrolyzer, 20,000 Nm3/h); reference case based on NREL ATB Class 5 onshore wind: capacity factor: 42% (current), 45% (2030), LCOE: $31/MWh (current), $22/MWh (2030); low case based on NREL ATB Class 1 onshore wind: capacity factor: 48% (current), 54% (2030), LCOE: $27/MWh (current), $18/MWh (2030); high case based on NREL ATB Class 9 onshore wind: capacity factor: 27% (current), 30% (2030), LCOE: $48/MWh (current), $33/MWh (2030)
5 Electricity unit costs are based on median, top quartile, and bottom quartile 2030 grid LCOE by census region from EIA Annual Energy Outlook 2022; assumes the same electrolyzer installed capex as (5); median LCOE: $68/MWh (current), $63/MWh (2030); top quartile LCOE: $66/MWh (current), $62/MWh (2030); bottom quartile LCOE: $89/MWh (current), $80/MWh (2030); Grid carbon intensities are based on data from the Carnegie Mellon Power Sector Carbon Index as well as national averages in grid mix carbon intensity – in some states, grid carbon intensity can be as high as 40 kg CO2e / kg H2 (absent power import / export across sate lines that can lower the carbon intensity of consumption, relative to generation)
6 Values with RNG not shown (which could include negative carbon intensities)
Sources: Hydrogen Council, NREL Annual Technology Baseline 2022, EIA Annual Energy Outlook 2022

Figure 2: SMR with CCS and electrolysis from clean energy have highest potential for low-cost clean hydrogen supply. Alternate technologies, like pyrolysis, have other market dependencies that drive uncertainty (Carbon intensities shown are well-to-gate)

The primary reformation-based production routes are:

- **Steam methane reforming (SMR):** SMR is a mature, carbon-intensive technology representing a $10–12B annual domestic market (<2% CAGR from 2015–2020) with ~10 MMTpa operational across the U.S.[iv] Carbon intensities of hydrogen made using steam methane reforming also depend on the extent of methane leaks during the production and transportation of the natural gas feedstock. Anticipated regulations and advances in methane monitoring are expected to reduce these emissions and provide greater measurement certainty.
- **Auto-thermal reforming (ATR):** ATR is a less prevalent gas reforming technology that produces more concentrated CO_2 streams, reducing CO_2 separation costs.
- **Other techniques include** methane pyrolysis; other gasification techniques, including biomass gasification (with and without CCS) and coal gasification; and several other reformation techniques that can co-produce power.[29,30,31] These production routes operate at a smaller scale in the U.S. and are not explored in this iteration of the Clean Hydrogen Liftoff report.

Reformation-based production can be partially decarbonized to reduce up to ~60% of total CO_2e emissions by adding carbon capture with storage (CCS).[vii] CCS adds up to $0.4/kg to hydrogen production costs, depending on the geography, capture rate, and reformation technology.[xii,32,33] By 2050, reformation-based production with CCS may account for 50–80% of total U.S. hydrogen production (see Chapter 3, Figure 14).

Several carbon capture approaches are available to decarbonize the more than 10 MMTpa of reformation-based hydrogen production that is already operational in the U.S. and emits ~100 million metric tonnes pa of CO_2 today.[34] Point-source capture technologies such as amine-based solvents are well established, and ~25 million metric tonnes pa CO_2 of domestic capacity is already operational across various industries.[35] Amine-based solvents can capture 95% of point-source emissions from ATR vs. 90% from SMR, although within error bars, some studies suggest CCS capture rates may be agnostic to the reformation-based production pathway chosen.[xii] Reformation-based hydrogen, which uses natural gas as a feedstock, will also have upstream emissions from natural gas production and distribution.

Clean hydrogen producers are expected to take advantage of either the hydrogen PTC (45V, IRA) or the carbon sequestration tax credit (45Q, IRA) to improve near-term project economics.

- The IRA's hydrogen PTC offers a range of credit values based on the carbon intensity of the production pathway, up to $3/kg for <0.45 kg CO_2e/kg H_2, assuming prevailing wage and apprenticeship requirements are met.[36] Calculations for qualification under 45V include upstream emissions of methane during production and transportation of the natural gas feedstock, a topic not covered in this Liftoff document.
- The IRA's enhanced 45Q tax credit increased the value of sequestered carbon from $50–$85/ton.

29 Methane pyrolysis: Project economics for this production method frequently depend on the prevailing price of carbon black, a high value material used in tires, plastics, and chemical films. Carbon black is a small, low-growth global market (~$14B in 2021, 4.6%). If alternative uses of carbon black are not identified, there is some risk that overproduction of hydrogen via methane pyrolysis could flood the domestic market with carbon black beyond its relevant use and depress its price significantly. Beyond the current market limit, new uses for carbon black would need to be developed (e.g., cost-effective syntheses of graphite, carbon fiber, or carbon nanotubes – for more, see publications from ARPA-E and industry partners like Huntsman). Carbon black market size and growth rate are from Stevens, Robert, Eric Lewis, and Shannon McNaul. Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies. No. DOE/NETL-2021/2743. National Energy Technology Laboratory (NETL), Pittsburgh, PA, Morgantown, WV, and Albany, OR (United States), 2021.
30 Biomass gasification/pyrolysis can produce zero or negative CI hydrogen, but logistics require further development to reach scale. If applied with CCS, biomass gasification provides a carbon-negative pathway by providing a vector for biogenic/atmospheric carbon to be sequestered.
31 Note that coal gasification, with a carbon intensity of 16-20 kg CO_2e/kg H_2, is also a common production route, representing 18% of global production, but it accounts for a small share (<1%) of U.S. production.
32 CCS can capture carbon at the point of hydrogen production, upstream fugitive emissions from natural gas extraction, processing and transport should be considered in lifecycle greenhouse gas emissions accounting. These fugitive emissions are highly variable but have been estimated at 1-3% of withdrawn natural gas by volume.[i],[ii], representing 1-3 kg CO_2e/kg H_2 for SMR production.[iii] SMR/ATR production with CCS will have a non-zero life cycle carbon intensity that will vary based on the natural gas upstream supply chain. [iv] 33 Assumes up to $60/tonne CO_2 transport and storage cost. See the [Carbon Management Commercial Liftoff] report for detailed cost comparisons.
34 Calculated based on carbon intensities in Figure 2
35 Global CCS Institute, public announcements as of March 2022
36 See Inflation Reduction Act, Section 45V, Hydrogen Production Tax Credit. The hydrogen PTC is also referred to as "45V".

The preferred subsidy for reformation-based projects with CCS will be project-dependent based on the carbon intensity and capture rate of the facility. Because the value of the hydrogen PTC scales with lifecycle emissions of produced hydrogen while the 45Q credit does not, the 45Q credit may be more attractive for projects with higher upstream methane emissions and higher pre-capture carbon intensity. Using biogas and renewable natural gas instead of fossil-based natural gas could also decarbonize reformation-based hydrogen, but without subsidies is not economically competitive relative to decarbonizing with CCS.[37]

In contrast to reformation-based approaches, water electrolysis uses electricity to break apart a water molecule into hydrogen and oxygen via an electrolyzer.[viii] It is the other dominant production technology for clean hydrogen, receiving significant attention and investment outside the U.S. For example, ~500 electrolyzer projects over 1 MW are announced, under development, or operational in Europe accounting for ~20 MMTpa of potential clean hydrogen production.[38]

The carbon intensity of this process is primarily based on the type of power (i.e., energy feedstock) used to run the electrolyzer, including:[39]

- **Dedicated zero-carbon electricity:** Non-emitting energy sources such as solar, wind, nuclear, and hydro can produce hydrogen with carbon intensities lower than 0.45 kg CO2e/kg H2, qualifying for the full production tax credit (PTC, $3/kg of H2). Renewable capacity factors will impact hydrogen production costs; the electrolyzer's levelized capital expenditure (capex) cost is inversely proportional to the capacity factor. However, pairing solar and wind energy or using battery storage can improve capacity factors to lower the levelized costs. Electrolyzers using hydro and nuclear power can run at high-capacity factors (>90%) allowing for lower levelized capex costs.
- **Renewable or nuclear electricity with synchronous power purchase agreements (PPAs):** Non-dedicated clean electricity sources can also be contracted through PPAs. Additional regulatory clarity for producers seeking to capture the PTC would help accelerate further private upstream investment.
- **Electricity via the grid:** Electricity from the grid enables high electrolyzer utilization, however, in most instances in the United States today it will result in higher carbon intensity than natural gas reformation.[40] When electrolyzers are powered by the grid in states with the highest fossil penetration carbon intensity (CI) may be as high as 40 kg CO2e/kg H2 (with national median at ~20 kg CO2e/kg H2).[ix] As the grid decarbonizes due to favorable economics and IRA incentives for clean electricity, so too will the carbon intensity of hydrogen production powered via the grid.

37 Assumes 5% RNG blend with $80/MMBtu ag RNG at CI = -300gCO2e/MJ, $3/MMBtu non-renewable natural gas. CCS results in lower levelized cost of hydrogen over wide range of capture costs from $20–70/tonne CO2
38 Based on the Hydrogen Council and McKinsey Hydrogen Insights P&I tracker as of the end of 2022
39 Thermal inputs can offset electricity consumption and increase electrical efficiency (electricity is the primary but not sole input to electrolyzers)
40 When variable RES are used, the load factor is also critical because it determines the levelized capex cost, as well as the size and cost of hydrogen storage required – impacting overall levelized cost of hydrogen

Four electrolyzer technologies are at various stages of commercial readiness:

High / Low

Technology	Applications	Degree of maturity	Industry forecasts for system capex excluding installation[1,2,3], $/kW	Advantages	Disadvantages
Alkaline Water Electrolysis (AWE)	Industrial applications (e.g., ammonia, refining, steel, chemicals)	Established technology; commercial stage	Current: 760-1,000; 2030: 230-400; -60%	Cost-effective, mature technology No PGM[4] catalysts	Low current density Corrosive electrolyte
Proton Exchange Membrane (PEM)	Diverse use cases, including road transport Distributed hydrogen production Grid balancing	Increasing scale-up; commercial stage	Current: 975-1,200; 2030: 380-450; -60%	Simple cell design and small footprint High current density Differential pressure operations High dynamic response	Scale-up constrained by PGM supply and PFAS[5] usage Less demonstration of long-term durability vs. AWE
Solid Oxide Electrolysis Cell (SOEC)	Low purity industrial use cases Co-location with high temperature steam	Laboratory / early commercial stage	Current: 2,000-2,500; 2030: 300-500; -80%	Low electricity demand using steam (high efficiency) No PGM catalysts	Heat / steam source required Limited dynamic response Durability challenges with high-temperature operations
Anion Exchange Membrane (AEM)	Distributed hydrogen production Grid balancing	Latest technology, limited deployment; laboratory stage	*Estimates not available*	Potential for: • No PGM catalysts • High current density • Differential pressure operations • High dynamic response	Limited performance and lifetime with current material systems

1 System capex incl. stack, transformer and rectifier, compressor for 30 bar compression, purification/drying for 99.9% purity. 2022 for 2 MW system, 2030 for 80 MW system; range based on median and top quartile performance
2 These levelized costs use industry estimates for electrolyzer capex costs developed in 2020 using 2020 USD. Forecasted electrolyzer capex values are rapidly evolving and may differ between sources; ranges have been expanded to include both Hydrogen Council and Bloomberg New Energy Finance data for AWE and PEM electrolyzers
3 Electrolyzer installed capex values: AWE, 2022: $1,380-1,420/kW (2 MW); AWE, 2030: $400-550/kW (80 MW); PEM, 2022: $1,700-1,800/kW (2 MW); PEM, 2030: $500-600/kW (80 MW); SOEC, 2022: $3,500/kW (2 MW); SOEC, 2030: $700-800/kW (80 MW). Installed capex also includes assembly, transportation, building, and installation costs
4 Platinum group metals
5 Per- and Polyfluorinated Substances
Source: Bloomberg New Energy Finance, Hydrogen Council

Figure 3: Industry estimates related to electrolyzer capex cost-downs. Figure to be updated when DOE internal numbers are available for publication. Electrolytic hydrogen production will likely come from a range of technologies; AWE is most mature and certain to scale for near-term industrial uses due to low-cost and absence of PGM catalysts. PEM must overcome challenges to increase scale up, while SOEC is unproven at scale

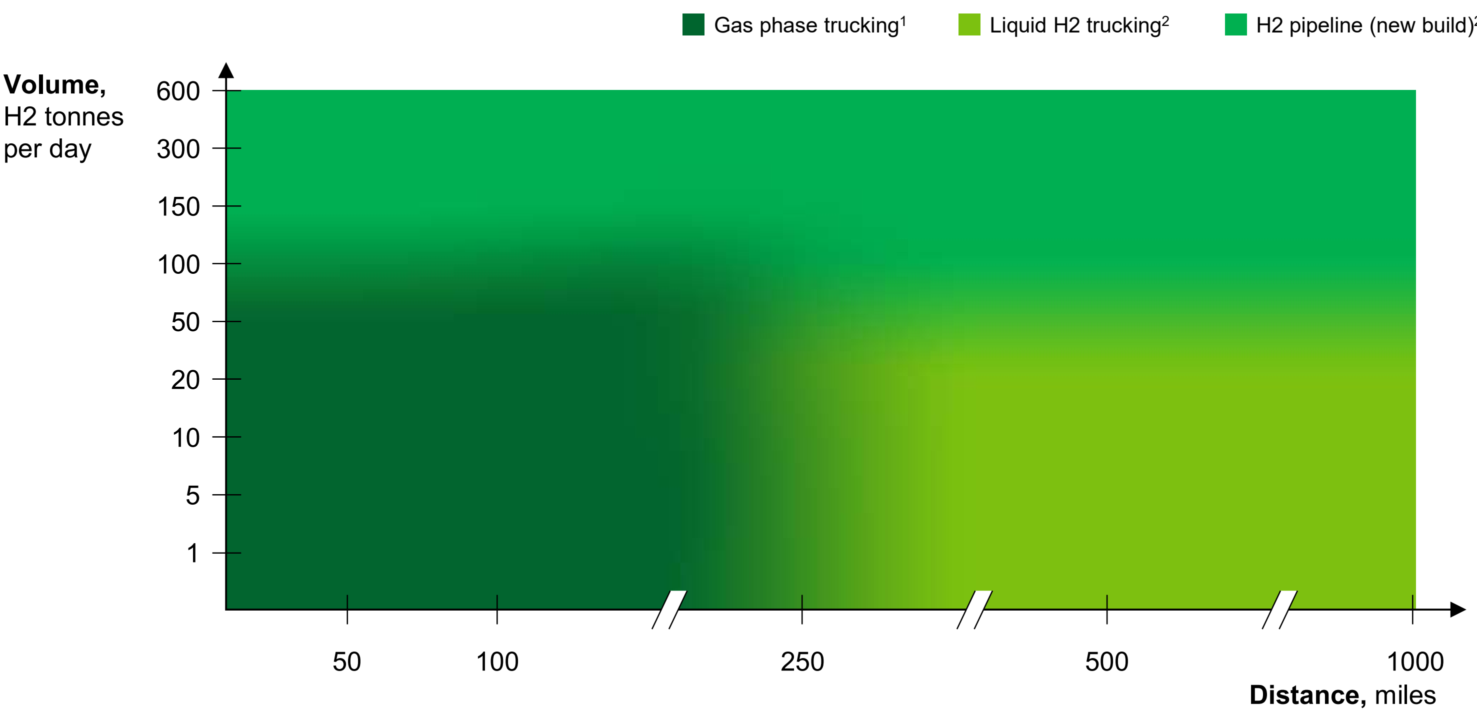
As shown in Figure 3, the capex costs for electrolyzers forecasted by manufacturers are expected to decline rapidly through 2030. Lower capex will be the largest driver of near-term electrolysis cost reductions (through 2030) (Figure 2, Figure 11). However, these industry forecasts do not yet reach the Hydrogen Fuel Cell Technology Office (HFTO) targets of ~$100 - $250/kW (late 2020s to early 2030s) motivating the need for additional R&D funding to bridge the gap.[37]

Midstream: Distribution and storage[41]

Today, the U.S. operates midstream infrastructure that distributes and stores hydrogen including 1,600 miles of dedicated hydrogen pipelines and three salt caverns for geologic storage.[42] Pipelines and geologic storage are costly upfront to develop, but at high hydrogen volumes provide critical economies of scale. Dedicated hydrogen pipelines and low-cost geologic storage are expected to anchor hydrogen infrastructure in the long-term (post-2035). More modular solutions—such as gaseous or liquid trucking—are needed to move hydrogen in lower volumes (<50 tonnes/day), with some boundary conditions for hydrogen distribution shown in Figure 4. As described throughout this report, in the near-term limited availability of midstream infrastructure is a constraint for scaling clean hydrogen where co-located production and offtake is not feasible, representing a key challenge that must be addressed.

Hydrogen Distribution

Preferred hydrogen distribution method by volume and distance



1 Assumes hydrogen is compressed to 500 bar and transported in 1100 kg truck
2 Includes liquefaction and liquid transport (fuel and labor)
3 Assumes hydrogen is compressed to 80 bar and transported in a newly built, dedicated H2 pipeline. These results do not consider leveraging existing pipelines

Source: Heatmap is based on data from the Hydrogen Council and the Hydrogen Delivery Scenario Analysis Model at Argonne National Laboratory, but left qualitative to highlight uncertainty in distribution methods and case-by-case variability

Figure 4: Pipelines are the preferred solution at large volumes, but will likely not be needed until ~2030 when offtake scales

41 This report refers to hydrogen "distribution" to mean the movement of hydrogen molecules – regardless of scale or mode of movement.
42 In contrast, more than 3 million miles of natural gas pipeline are operational across the U.S.

Note that there is no single, optimal hydrogen delivery solution for every production schedule, distance/volume transported, and set of end-use requirements. Offtakers that are not co-located with producers or connected via a pipeline must evaluate the cost-effectiveness of gaseous vs. liquid trucked hydrogen for their particular use case, and the extent to which pipeline retrofits will be possible. Common trade-offs and levelized costs are provided in Figure 5. A few examples highlight the range of least-cost approaches pursued around the world:

- To date, Europe has relied on a predominantly gaseous trucking network because transport regulations, driver cost/wages, and distances travelled generally make gaseous hydrogen less expensive than liquid distribution. Forecasting growth of the hydrogen economy, some European energy infrastructure operators are planning an extensive gaseous pipeline network, with a length of almost 53,000 km by 2040, largely based on repurposed existing natural gas infrastructure.[x]

- In the U.S., existing producers of hydrogen have pursued a predominantly liquid network with a gaseous distribution network at small-scale, while larger domestic offtake is currently served by co-located production and 1,600 miles of dedicated hydrogen pipeline.

Distribution method	**Key characteristics**	**2030 levelized cost, including compression / liquefaction,** $/kg
Gas phase trucking[1]	• H_2 **gas is compressed at ambient temperature** to 300 – 500 bar • **Ideal for short distances and small volumes** (≤ 20 TPD) due to lower capex costs for compressors and tube trailers vs. liquid and pipeline transport • **Lower transport capacity** due to the low volumetric density of H_2	0.9-1.9
Liquid hydrogen trucking[2]	• **Cryogenic cooling to liquefy hydrogen**, followed by storage in cryogenic tankers • **Ideal for larger volumes where pipelines are not feasible** and longer distances to minimize the number of trips and driver labor cost • **Higher capex costs than gas phase trucking** but lower than pipelines	2.7-3.2
Dedicated hydrogen pipeline transport[3]	• **Underground pipeline** transporting compressed gas phase hydrogen • **Lowest levelized cost at high volumes** (50+ TPD) **and long distances** due to low opex costs; not commonly used for lower volumes • **Requires permitting approval and high upfront capex costs** ($2-10 million per (inch-mile) for 6–14-inch diameter pipes)	0.2-0.5
Hydrogen / natural gas blended pipeline	• **Blending of up to ~20% hydrogen by volume into natural gas pipelines** for use in the power and heating sectors • **Blending rates are limited** due to leakage and required compressor modifications, but work is underway to refine volume threshold • **Separation** of hydrogen from natural gas **can be very expensive**	*Dependent on blending volume and retrofit costs*

1 Assumes hydrogen compressed to 500 bar and transported 250 km; 50 TPD compression capacity; Source: Hydrogen Council
2 Assumes hydrogen liquefied and transported 250 km; 50 TPD compression capacity; Source: Hydrogen Council. Range based on increased leak rate and liquefaction costs.
3 Assumes 600 TPD hydrogen compressed to 80 bar and transported 300 km; range represents difference between high-cost region (New England) and low-cost region (Great Plains); Source: Hydrogen Delivery Scenario Analysis Model, Argonne National Laboratory

Figure 5: Industry-informed distribution costs. Gas trucking is suitable for short distance/small volume transport while liquid trucking is preferred for higher throughput use cases over longer distances when pipelines are not available or practical

Gaseous trucking networks can offer significantly lower capex compared to liquid trucking networks. This cost differential is driven almost entirely by the higher installed cost of a liquefier (for liquid trucking) than compression equipment (for gas trucking).[43] In addition, gaseous hydrogen can be easier to provide to smaller offtakers via trailer swapping (instead of through low-temperature liquid transfer or vaporization to a gas from liquid trailers). Due to lower capital intensity and cost-effective operation at much smaller scales, gaseous hydrogen production and distribution can offer lower barriers to entry. This could enable smaller-scale project development across the value chain, driving fragmentation and competition among producers and distributors. In some cases, increased competition could contribute to reductions in the cost of gaseous hydrogen, making it an important pathway to extend hydrogen beyond regional infrastructure clusters (which will see economies of scale) and to remote areas that might not otherwise be served.

Gaseous hydrogen equipment can also be easier to pair with off-grid renewables. Liquefiers are not as easily compatible with off-grid renewable power because they have less favorable turn-down ratios and very long power cycling. In contrast, compressors for gaseous ecosystems have more flexible turn-down ratios and power cycles, making them a stronger match for off-grid variable renewables. Pairing hydrogen production with off-grid renewables could accelerate renewable energy deployment and hydrogen ecosystem growth in parallel, by avoiding power line siting and connection queue issues. Note that any hydrogen production system connected to a renewable energy source that does not have on-site power back-up or grid connectivity will require on-site hydrogen storage to manage hydrogen production intermittency which can add cost (see Figure 6 and storage section below).

In addition to trucking liquid or gaseous hydrogen, hydrogen can be distributed via pipeline. Dedicated hydrogen pipelines can move large volumes over long distances to achieve economies of scale ($0.2-0.5/kg for distributing 600 tonnes per day 300 km). However, initial pipeline construction is time and capital intensive. Pipelines also require a stable, credit-worthy offtakers who will demand significant volumes of hydrogen sufficient to justify dedicated infrastructure build-out. The United States has ~1600 miles of dedicated hydrogen pipelines today.[iii]

Initiatives are underway to explore blending hydrogen into existing pipeline networks. This includes blending hydrogen into domestic natural gas pipelines at up to 20% by volume (2–7% content by energy density), with a small number of demonstration projects up to 30%.[xi,44] Blending can move significant volumes of hydrogen. However, separating and purifying the hydrogen from natural gas is difficult. Blended hydrogen and gas also require end-use equipment that can take a blended fuel. When blending >5 – 10% hydrogen, appliances connected to the pipeline may have to be qualified or converted to the hydrogen blend, a challenging transitional effort (note that Hawaii blends as high as ~15% without retrofits of end-use appliances).[45,xx] In addition, if blend ratios change, appliances could require further upgrades. For residential uses, hydrogen blends also need to compete with electrification as a decarbonization alternative. Electrification is in most cases less expensive than use of blends, and in many cases it can be an easier to transition home appliances to electricity than it can be to transition them to the use of blends.

43 Innovations in high pressure hydrogen compression equipment have allowed for significantly higher throughput compressors with concurrent cost reductions from system scale. Combined with improved system reliability and efficiency, these systems bring both total installed cost and operating costs well below compression systems available prior to 2020.
44 DOE's HyBlend initiative aims to address technical challenges to blending hydrogen in natural gas pipelines. Key aspects of HyBlend include materials compatibility R&D, techno-economic analysis, and life cycle analysis that will inform the development of publicly accessible tools that characterize the opportunities, costs, and risks of blending.
45 Decarbonization: Hawaii gas. (n.d.). Retrieved January 3, 2023, from https://www.hawaiigas.com/clean-energy/decarbonization

Hydrogen Storage

For hydrogen storage, compressed gaseous hydrogen storage in a pressure vessel has the highest levelized cost but is easiest for low volumes, as detailed in Figure 6. Liquid hydrogen storage has lower levelized cost but requires higher overall capex and can experience boil-off losses (particularly during longer storage durations), making it appropriate for larger volumes and scenarios with high utilization.[46] Geologic storage in salt caverns and hard rock caverns has the lowest levelized cost but is geographically limited and cost-effective only for very large volumes.

Distribution method	**Key characteristics**	**2030 levelized cost[1], $/kg**
Compressed gas tank storage[2]	• H2 **gas is compressed at ambient temperature** to 300 – 700 bar • **Storage capacity is limited** due to the low volumetric density of H2 at room temperature • **Highest unit cost** option, but **lower total capex** cost due to smaller scale • **Storage capex costs** expected to decline from ~$550/kg to ~$400/kg in 2030	0.8-1.0
Liquid hydrogen storage[3]	• **Cryogenic cooling** to liquefy hydrogen, followed by storage in insulated tanks • **Allows storage of large volumes** of hydrogen, but requires large total capex investment • Hydrogen liquefaction **uses >30% of the hydrogen energy content** • Liquid hydrogen is **not viable for long-term storage** (>10 days) • **Storage capex costs** expected to decline from ~$120/kg to ~$100/kg in 2030	0.1-0.3
Salt cavern storage[4]	• **Geologic formations created by salt deposits** that can store gaseous hydrogen at elevated pressure (70-190 bar) • **Large-scale storage and low capital costs**, but also **limited availability** (~2000 salt caverns in North America with an average capacity of 10^5-10^6 m^3) • Salt caverns **can also store other gases** (e.g., natural gas), so there is **competition for cavern usage** • **Storage capex costs** expected to remain stable through 2030	0.05-0.15
Lined hard rock storage[5]	• **Underground cavern is surrounded by hard, low permeability rock**, which can be lined to hold pressurized hydrogen • **Earlier stage technology than salt caverns**, with limited hydrogen demonstrations but **expected to allow higher storage pressures** (up to 300 bar) • Storage capex costs expected to remain stable through 2030	0.1-0.3

1 Does not include cost of compression or liquefaction (included in transport costs)
2 Assumes 950 kg stored at 500 bar with 1 cycle per week; Source: Hydrogen Council
3 Assumes 1 cycle per week and 50 TPD volume, Range based on 0.5-2 cycles per week. Source: Hydrogen Council
4 Assumes capacity to store 600 TPD pipeline throughput for 7-days at 80 bar; cushion gas is ~40% of volume; Range based on 50-2000 TPD; Argonne National Laboratory
5 Assumes 150 bar storage with 1 cycle per week. Range based on 0.5-2 cycles per week. Source: Argonne National Laboratory

Figure 6: Industry-informed storage costs. Lined hard rock and salt cavern storage are geographically constrained but represent the largest scale and lowest-cost storage options. Large-scale production and offtake are likely to be built near these natural resources

While codes and standards informing design of hydrogen infrastructure enable safe operation, losses can occur throughout the supply chain that impact both financial performance and environmental benefits. Hydrogen is a small molecule that is more susceptible to leakage than methane, especially through threaded connections or via liquid boil-off.[xii,47] As the hydrogen economy scales, careful and rigorous attention must be paid to the emissions impact of hydrogen leakage (hydrogen has an indirect global warming potential), safety, and the impact on stakeholders and energy communities (see Chapter 3).

46 Liquid hydrogen begins to boil off after 10 days and needs to be vented and lost
47 Liquid boil-off is the hydrogen that vents from liquid storage tanks

Combined production and storage implications

Like most energy technologies, end-uses frequently require high-uptime, uninterrupted supply of hydrogen (e.g., for use in industrial and chemicals applications like ammonia production). Until low-cost hydrogen storage and trading is achieved, behind-the-meter production with variable renewable power may require a backup hydrogen supply. Gaseous value chains would need to deploy excess gaseous hydrogen storage (on-site or at an offtaker) to ensure reliable supply, increasing the total cost of delivered hydrogen. Or, liquid hydrogen distributors could provide backup supply to hydrogen offtakers, often at a significant price premium, since liquid transport allows long distance distribution of large hydrogen quantities.

Downstream: End-uses

Hydrogen can decarbonize a wide range of sectors, particularly for use cases where decarbonization alternatives are costly or impractical. Most demand by 2030 for low carbon hydrogen will be drop-in replacement for carbon-intensive hydrogen currently used in ammonia and oil refining. Sectors where hydrogen is not an incumbent technology, such as other industrial sectors (steel, chemicals), transportation, and gas replacement (heat and power), will take more time to develop without regulatory drivers. Figure 7 illustrates hydrogen's potential as a decarbonization lever across these sectors including associated switching costs and the potential market size (USD) for hydrogen as a feedstock in each application.

Largest long-term H2 feedstock TAM

Sector	End-use	Role of H2 in decarb.	Description of switching costs	H2 feedstock TAM[1], $ billion			H2 market size with full adoption[2], $ billion		
				2030	2040	2050	2030	2040	2050
Industry	Ammonia		**Low:** Process currently uses fossil-based H2, hydrogen supply feed in place	4-10	4-11	5-12	4-10	4-11	5-12
	Refining		**Low:** Hydrogen supply feed in place	6-8			6-8		
	Steel		**Variable:** Highly dependent on current plant configuration and feedstock, may also include hydrogen distribution infrastructure		4-7	4-8	15-30	18-35	20-40
	Chemicals-methanol		**Variable:** Can limit switching costs by adding CCS to SMR, other approaches more costly with higher unit cost savings		2-6	3-7	5-12	5-12	6-14
Transport[1]	Road[3]		**High:** New vehicle power trains with fuel cells, refueling stations & distribution infrastructure	0	25-30	40-55	90-125	110-140	120-160
	Aviation fuels		**Moderate:** Fuel conversion / production facilities		5-15	10-30	8-20	10-25	10-30
	Maritime fuels[4]		**High:** New ship engines, port infrastructure & local storage, and fuel supply, storage, and bunkering infrastructure in ports	< 1	4-10	8-20	5-15	5-15	8-20
Heating	NG blending for building heat[5]		**Variable:** Will depend on pipeline material, age, and operations (e.g., pressure); requires testing for degradation and leakage	0	0	0	2-3	2-3	2-3
	Industrial heat		**Variable:** Dependent on extent of furnace retrofits required	0	1-3	2-5	7-10	7-10	7-10
Power	High-capacity Firm – 20% H2 (Combustion)[6]		**Moderate:** Retrofits to gas turbines, additional storage infrastructure	< 0.2	< 0.1	< 0.1	4-6	5-8	8-12
	Power – LDES[7]		**Moderate:** Retrofits to gas turbines, additional storage infrastructure	0	4-6	8-11	Varies based on cost-downs in other LDES technologies and composition of grid		

1 Represents the market size for clean hydrogen feedstocks in each end use; calculated by multiplying the clean hydrogen in the "Net zero 2050 – high RE" scenario by range of willingness to pay by end use reported in the DOE National Hydrogen Strategy and Roadmap; dispensing costs are subtracted from the road transport TAM and market size with full adoption
2 Represents the maximum market size if the hydrogen-based solution had 100% share of each end use
3 H2 feedstock TAM uses H2 demand from the DOE National Hydrogen Strategy and Roadmap assuming both medium- and heavy-duty trucks; H2 market size with full adoption is based on energy usage from Class 8 long-haul and regional trucks, which represent the significant majority of all medium- and heavy-duty truck energy consumption
4 Maritime fuel demand and split between ammonia and methanol maritime fuel from the Mission Possible Project report "A Strategy for the Transition to Zero-Emission Shipping", assuming U.S. ports use 6% of global maritime fuel based on volume of fuel used in global ports
5 H2 TAM based on DOE National Hydrogen Strategy and Roadmap assumption that all hydrogen for heating is used for industrial heat; H2 market size with full adoption assumes 20% hydrogen blending by volume
6 Willingness to pay is based on high-capacity factor firm combustion
7 Long Duration Energy Storage (LDES) hydrogen demand and willingness to pay from DOE National Hydrogen Strategy and Roadmap

Figure 7: Hydrogen is a large and growing domestic market, from $80-150B by 2050. The largest markets are for hydrogen in industrial use cases, medium and heavy-duty road transport, and liquid fuels that use hydrogen feedstock. Some end-use segments were not analyzed in this iteration of the Liftoff report. End-uses not analyzed include (1) clean hydrogen combustion for peaking power (low-capacity factor) and (2) clean hydrogen combustion for intermediate range capacity factor turbines. In the presence of carbon constraints or other regulatory drivers, these use cases (1) and (2), may have a higher potential in the power sector than high-capacity use cases detailed above (Figure 7).

Overall, hydrogen feedstocks are expected to represent a $80-150B domestic market by 2050. Switching costs and sector-specific economics have implications on penetration rate and total addressable market (TAM). Figure 7 explores the TAM for hydrogen as a feedstock – first based on forecasts for end-use demand described in the DOE National Clean Hydrogen Strategy and Roadmap and then, illustratively, at 100% market adoption (details follow – also see Modeling Appendix – Methodology 7).[48]

Industrial feedstocks:

- **Ammonia:** Ammonia is a CO2 intensive compound that can drastically reduce its emissions footprint with low carbon hydrogen.[xiii,49] Roughly 70 percent of ammonia produced globally is for fertilizer use.[xiv] It is a low-margin commodity that is unlikely to see high willingness to pay outside of markets with strong carbon regulation (e.g., European Union). In the U.S., urea-based fertilizer would also require an alternative clean CO2 source.

  Existing domestic ammonia capacity (for fertilizer use) is expected to largely opt for reformation-based production pathways with CCS. However, the domestic fertilizer industry could contribute to cost-downs in electrolysis if electrolytic hydrogen replaces even a small share of the reformation-based hydrogen currently used in today's processes (due to the scale of domestic ammonia production today). If new markets for ammonia develop (e.g., as an energy carrier to ship clean hydrogen), electrolysis could be the chosen production method if domestic or international markets demand a higher willingness to pay for the lowest-carbon-intensity option, and have access to scaled, low-cost storage to support these use cases.

  As a hydrogen carrier, ammonia is also being explored as a maritime fuel and as a power source.[50] It has existing, mature global and domestic infrastructure including ~2,000 miles of domestic ammonia pipelines.[xv,xvi] This infrastructure can be used to export ammonia into countries that (A) lack natural gas resources and/or CO2 sequestration sites, or (B) lack an abundance of cost-effective renewable resources (e.g., Japan, South Korea), which could drive further growth in the U.S. ammonia production market.[xvii] However, domestic ammonia producers may face steep price competition from regions with high clean energy penetration, low construction costs, and fewer constraints related to project siting/permitting (e.g., Middle East).

- **Oil refining:** Approximately fifty-five percent of current domestic hydrogen consumption is allocated to refineries to remove sulfur and upgrade heavy oil into more refined fuels, and to hydrocrack heavier refinery products.[iii] This high carbon intensity hydrogen can be directly replaced with clean hydrogen.

48 TAM analysis is for illustrative purposes only and intended to show range of adoption scenarios. See Modeling Appendix for additional detail.
49 Several ammonia facilities have recently announced carbon capture and storage retrofits to the integrated SMR facilities that produce hydrogen for ammonia synthesis today. This method represents a lower-cost approach to capture additional revenue from the tax credits versus building new reformation-based or electrolysis-based hydrogen production.
50 Shipping involves heavy weights and long-ranges so liquid fuels with a higher energy density than hydrogen are needed. The two primary candidates for decarbonized maritime fuel are ammonia and methanol; different shipping companies are pursuing both pathways. While ammonia does not have direct CO2 emissions, it does have increased toxicity that must be mitigated with safety protocols. However, these protocols exist and are used at scale today in both domestic and export markets for ammonia. Conversely, methanol has low toxicity, but emits CO2 that must either be captured and sequestered or offset by using a carbon feedstock that uptakes carbon from the atmosphere (e.g., biomass).

- **Methanol:** Hydrogen and captured CO2 (e.g., via biological sources, point-source capture, or direct air capture – DAC) can create methanol. Methanol acts as a precursor for fuels, plastics, and many other goods. Today, natural gas reforming is the dominant pathway for methanol production due to the low cost of natural gas. Clean hydrogen may see strong potential in helping to decarbonize methanol production, however, the low-cost of incumbent technology presents a near-term challenge to the cost-effectiveness of lower carbon-intensity methanol which is reflected in Figure 7 TAM estimates in 2030 vs. 2040.[xviii]

- **Steel:** U.S. steel production is split into virgin production via blast furnace (BF-BOF, currently ~1/3 of production) and production via electric arc furnaces (EAF, currently ~2/3 of production). EAF can be used for secondary production via scrap-based electric arc furnaces or virgin production via direct-reduced-iron (DRI-EAF).[xix] Using clean hydrogen instead of fossil-based hydrogen or syngas can economically decarbonize DRI-EAF, which could account for 10-20% of steel production at scale.[51,ix] Because this method accounts for the smallest share of domestic steel production, hydrogen's use as a feedstock in steel production remains relatively flat through 2050 based on the DOE National Clean Hydrogen Strategy and Roadmap. BF-BOF is more economically decarbonized by installing carbon capture and sequestration, although hydrogen may be used instead of petroleum coke in the pre-blast furnace processing of feedstocks.[52] To reach the hydrogen market size with full adoption shown in Figure 7, U.S. steel production would need to completely transition to DRI-EAF production, which would likely require additional decarbonization policy to motivate the transition from BF-BOF and could result in a shortage of scrap steel for EAF.

Transportation: Hydrogen can play a multi-faceted role in the Transportation sector. It can be used directly in fuel cell powered machines or indirectly via synthetic fuels. Technology selection will be based on the range of required operating conditions and the cost/performance of alternative decarbonization technologies (e.g., electrification).

- **Road transportation:** Road transportation comprised 33% of 2019 U.S. greenhouse gas emissions, mostly reliant on diesel and gasoline.[53] Medium and heavy-duty vehicles account for about one-fifth of the domestic transportation sector's emissions.[xxxii] For road transport, clean hydrogen is most applicable when fuel cell vehicles are relatively more competitive compared to battery electric vehicles for a particular set of cost/performance requirements. Examples could include: (1) heavy-duty transportation, where battery weight, cost, and range can impact payloads; (2) cold regions where battery range may drop as compared to battery range in less cold regions; (3) high uptime use cases where charging may not be sufficiently fast or grid costs for fast charging (or fleet charging) may be prohibitively high.

  In these instances, transportation applications may prefer to use fuel cells (directly powered by hydrogen) or hydrogen-derivative clean fuels (produced through bio-based or synthetic processes).[54,55] Fuel cell electric vehicles (FCEVs) can maintain high uptime due to fast refueling and at-scale could be serviced by low-cost infrastructure. However, FCEVs require significant upfront investment to create economies of scale in both vehicle production and refueling stations. Hydrogen-derivative clean fuels are compatible with current vehicles and refueling infrastructure.

  FCEVs are expected to play a significant role in medium and heavy-duty transport, though scaling up FCEV trucks requires significant investment in refueling infrastructure, truck manufacturing, and innovation to reduce vehicle capex cost and improve fuel cell durability (>$250B by 2050).[56,57] Similarly, auto manufacturers are likely to face a steep required ramp-up of production capacity. If cost-downs are achieved, heavy-duty FCEVs should be cost-competitive with incumbent and alternative vehicles on a per-passenger- or ton-mile basis (see Figure 15 - total costs of ownership by end-use and Figure 27 – in Modeling Appendix). Regulatory drivers may also affect the timing of FCEV uptake.

51 An alternative approach for both BF-BOF facilities and natural-gas-based DRI+EAF facilities would be to add CCS infrastructure rather than converting to hydrogen. The capex costs associated with this CCS retrofit depends on the hydrogen concentration being fed into DRI; complexity and cost increases beyond 30% hydrogen
52 Another option being pursued in Europe is replacing the full BF-BOF process with DRI+EAF with hydrogen; however, this conversion is not yet being pursued in the U.S. and faces challenges around the location of steel plants relative to the best sources of cheap and reliable hydrogen
53 EPA "Inventory of U.S. Greenhouse Gases and Sinks"
54 The total potential volume of biofuels production could be limited by land use constraints and food security concerns. As a result, in the long-term biofuel volumes will likely go to transport use cases with the fewest decarbonization alternatives, and therefore a higher willingness to pay (e.g., aviation). Industry perspectives also vary significantly on decarbonization potential from biofuels and dynamics around land use.
55 Power-to-liquid fuels (sometimes called e-fuels) are synthetically produced hydrocarbons that are created by combining low-carbon power, catalysts, clean hydrogen, and captured carbon dioxide to produce fuels such as methanol, ammonia, and kerosene.
56 See DOE's Million Mile Fuel Cell Truck initiative
57 See Modeling Appendix for description of methodology for calculating required investments

Note that hydrogen has also been successfully deployed in non-road vehicle applications with high-payload, high-uptime requirements (e.g., forklifts). Many materials handling equipment use cases requiring high uptime are expected to switch to hydrogen (e.g., construction vehicles, airport ground transport equipment).

- **Aviation (Fuels):** The aviation sector has limited pathways to decarbonize due to aircraft range/weight constraints as well as limitations imposed by existing airport designs/operating models.[58,59] Sustainable aviation fuel (SAF), produced through bio-based or synthetic (power-to-liquid) technologies, provides a "drop-in" replacement that can be blended up to 50% in existing aircraft.[60] Both SAF production methods, bio-based and synthetic, use clean hydrogen as an input.

  Regional aircraft can run on pure hydrogen fuel, but long-haul aircraft with pure hydrogen would require new airframes (dependent on FAA approval timelines) and significant changes to airport gate/operating infrastructure. In addition, new aircraft designs would require fleet turnover is an industry where asset turnover is slow.[xxix] These factors mean that hydrogen-powered flight for long-haul aviation—the bulk of the sector's emissions—may remain multiple decades away and SAF is likely to be the most viable pathway for rapid decarbonization for the bulk of the industry's emissions.[61]

- **Marine (Fuels):** There are multiple approaches to decarbonize maritime emissions, however, the industry is still evaluating technical and performance trade-offs to determine the most likely pathway.[xx] Port and regional maritime equipment may electrify with batteries, or use hydrogen or its derivatives (e.g., ammonia, methanol, biofuels, and e-fuels).[xxix] Approximately half of U.S. marine vessel emissions are from international shipping, thirty percent are from domestic shipping, and roughly twenty percent are from recreational vessels.[xxix] There are opportunities for both hydrogen and hydrogen carriers across these segments, and in pier-side applications (e.g., stationary generators, drayage trucks). International cargo shipping requires prohibitively large volumes of hydrogen and is likely to need more energy dense replacements. Biofuels are unlikely to be a scalable solution based on constraints on volume and price of sustainable feedstocks. Hydrogen-derivative low carbon fuels (e.g., clean methanol, clean ammonia) are promising, but the future fuel mix is not yet certain within the industry. Each has feedstock, emissions, or safety challenges (e.g., onboard containerization) that will require international standards agreements, further technical progress, and investigation in follow-on Liftoff reports.

Gas Replacement – Heating: Hydrogen can be blended or directly used for heating. Residential and commercial heating requires low-grade heat (<300 C). Industrial applications typically require high-grade heat (>300 C), which has fewer decarbonization alternatives and therefore a higher willingness to pay for clean hydrogen.

- **Residential and commercial heating:** At >5-10% blending natural gas concentration, retrofits are expected to be required for end-use appliances (e.g., furnaces, stoves). However, there are examples of blending as high as 15% without end-use retrofits (e.g., State of Hawaii). Multiple competing alternatives (e.g., electrification via heat pumps) leave hydrogen challenged for residential and commercial heating in many regions.

58 For example, new propulsion systems and new onboard storage systems
59 Long range hydrogen aircraft would need to adopt new designs that would prevent them from using current airport gate infrastructure
60 International Air Transport Association (IATA) - Fact Sheet 2, Sustainable Aviation Fuel: Technical Certification, https://www.iata.org/contentassets/d13875e9ed784f75bac90f000760e998/saf-technical-certifications.pdf
61 "Flights greater than 1,000 nautical miles represent 65% (of the aviation sector's) total fuel usage" via the U.S. Department of Energy, "The U.S. National Blueprint for Transportation Decarbonization", 2023, page 72.

- **Industrial heating:** The unit costs of industrial retrofits are much lower than those for residential and commercial hydrogen use for heat. Industrial heating — particularly for applications such as glass and cement that require high temperature heat —represents 31% of the U.S. manufacturing sector's total energy-related emissions.[62,xi] In most instances, high-temperature process heat cannot be efficiently reached by electrification, and the amount of carbon produced is not sufficient to efficiently capture, transport, and store, making CCS cost ineffective. As a result, hydrogen could be a viable decarbonization solution for high temperature industrial heat. To fully implement hydrogen for industrial heating, however, several challenges must still be overcome, including burner design and management of NOx produced from high-temperature combustion.

Gas Replacement – Power sector: Hydrogen can be used in the power sector (1) as a high-capacity factor firm (dispatchable) power source; (2) as a lower-capacity factor power source; (3) as long-duration energy storage or (4) for grid resilience events.

- **Generation Capacity:** Hydrogen can provide high-capacity factor firm and lower-capacity factor power through several generation pathways, including:
  - **Combustion:** Hydrogen can be blended with natural gas for co-firing in some types of existing combustion turbines for high-capacity firm or lower-capacity factor power. Turbine manufacturers also have plans to develop designs capable of operating with blended and up to 100% hydrogen intake
  - **Fuel cells:** Fuel cells can provide peaking power – assumptions and considerations are detailed in Chapter 3

- The future role of hydrogen for high-capacity firm and lower-capacity factor power will depend on its economic and technical feasibility, along with continuing policy developments, relative to other low-carbon options.[63] As shown in Figure 10, with the PTC applied, electrolytic production costs are estimated to fall to less than \$0.40/kg by 2030.[64] This could translate to ~\$0.70 / kg to ~\$1.15 / kg delivered cost of hydrogen depending on storage and distribution method chosen.[65]

- **Long Duration Energy Storage:** For long-duration storage, hydrogen stored in salt caverns (where available) can represent a cost competitive approach for seasonal renewables load shifting (e.g., ACES project). The LDES Commercial Liftoff Report contains more details on the long duration storage market including competing technologies. For grid resilience events, where power plants are used 2-5% of the time during extreme weather, hydrogen is the likely new-build plant solution owing to extremely low power storage costs, though natural gas with carbon management may compete in some areas.[66]

Section 2.b: Current projects

Key takeaway

Currently announced clean hydrogen production projects would meet 2030 demand, with announcements accelerating; 50% of total planned capacity was announced in 2022, although ~10.5 MMTpa of the announced 12 MMTpa is still pre-final investment decision (FID) (Figure 8, 9).

62 Note that even with the exclusive use of hydrogen, ~50% of cement CO2 emissions comes from releasing CO2 when converting calcium carbonate rocks to calcium oxide (clinker). In this case, hydrogen is a partial decarbonization solution for the cement/concrete industry (replacing natural gas combustion, but not addressing emissions due to the chemical reaction in the clinker manufacturing process).

63 Several projects related to clean hydrogen applications in the power sector have been announced by utilities including, NextEra, Los Angeles Department of Water and Power, NY Power Authority, and Intermountain Power and the Long Ridge Energy Terminal Power Project

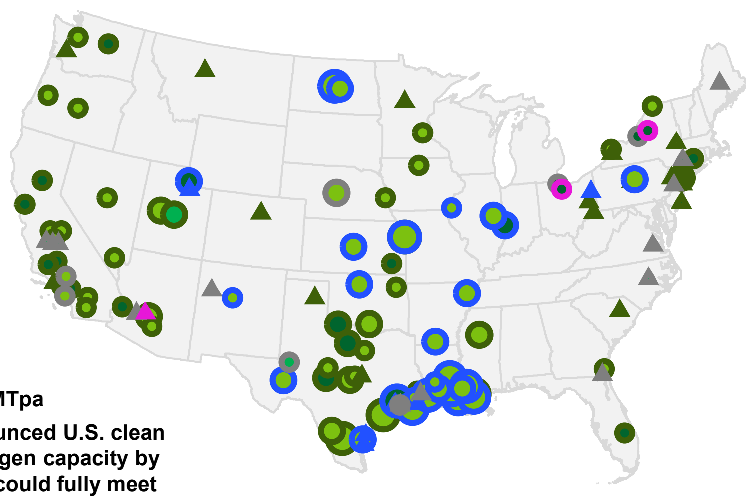
64 For electrolysis: \$0.40/kg is an upper bound example on cost of electrolytic hydrogen when the PTC is applied in a given year / point-in-time. At point-in-time, when credits are active, clean hydrogen costs can go negative. However, if investors apply a discounted cash flow (DCF) to calculate the value of the credit (10-years) over 25+ year asset life, the value of the credit will fall from \$3/kg (point-in-time) to ~\$1.4/kg (applying DCF on the value of the PTC). For reformation-based approaches: An LCOH range of ~\$0.40 - \$0.85/kg is similarly a point-in-time calculation if subtracting ~\$0.75/kg PTC for an SMR with CCS (as an example). If using a discounted cash flow methodology when applying a \$0.75/kg PTC, then LCOH for reformation-based projects with CCS could range from \$0.80 - \$1.25/kg (10 year credit duration, 25 year asset life).

65 Range assumes lowest-cost clean hydrogen production in 2030 as well as a range of distribution / storage options (compression to pipeline, pipeline, and storage fee associated with pipeline storage)

66 Hunter, C. A., Penev, M. M., Reznicek, E. P., Eichman, J., Rustagi, N., & Baldwin, S. F. (2021). Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids. Joule, 5(8), 2077-2101. doi:10.1016/j.joule.2021.06.018

Over 100 clean hydrogen production projects totaling ~12 MMTpa in production capacity have been announced across the U.S. with more than $15 billion of potential investment.[67] If these projects are all built, they would meet the projected ~10 MMTpa clean hydrogen demand by 2030, though these numbers will evolve: some projects will not be completed and new projects will be announced. Only ~1.5 MMT of this announced capacity has reached final investment decision (FID), largely owing to these projects lacking contracted offtake.

While the hydrogen PTC creates a supply-side/production incentive, the hydrogen will need demand-side pull to scale – which could include a regulatory driver. Without additional policy, offtake contracts (demand-side pull) will may be limited to co-located facilities until investment in midstream and downstream infrastructure occurs. In some cases, potential hydrogen offtakers have expressed hesitation due to: (1) *delivered* hydrogen prices being much higher than *production* prices, (2) future clean hydrogen prices potentially being lower than what can be contracted today, and (3) uncertainty about the reliability of supply at smaller than industrial scales (see Chapter 4).



12 MMTpa

Announced U.S. clean hydrogen capacity by 2030 could fully meet 10MMTpa expected demand

Clean hydrogen production projects

1.4 MMTpa

Clean hydrogen production projects

Production projects which are being developed independently from midstream infrastructure and end uses

Integrated projects

10.5 MMTpa
(0.5 MMTpa operational)

Integrated projects

Projects where production is co-developed with midstream infrastructure and / or specific end use(s)

Midstream and end use projects

< 0.1 MMTpa

Midstream and end use projects

Projects focused on midstream infrastructure and / or end uses without production co-development

Announced H2 capacity, ktpa		**Hydrogen Pathway**		**Project type**		
>150	0 - 20	Renewables w/ electrolysis	Nuclear w/ electrolysis	Clean hydrogen production projects	Midstream and end use projects	Integrated projects
20 - 150	N/A	SMR/ATR + CCS	Methane pyrolysis / N/A / Other			

Source: McKinsey Hydrogen Insights P&I tracker & Electrolyzer supply tracker as of end of 2022. Project trackers vary the way in which they log announced capacity – for example, Energy Futures Initiative has tracked more than 2.2 MMTpa from 42 announced projects – see The U.S. Hydrogen Demand Action Plan (February 2023) - "A review of the clean hydrogen project announcements shows a strong investor preference for green hydrogen (i.e., produced with renewable energy via electrolysis) over other pathways. Such preference in part seems to be driven by the downward scalability of electrolyzers, giving firms the ability to make relatively small investments. Other technologies, like blue hydrogen are not scalable and require large capital investments (see Appendix A for a description of different hydrogen production pathways). As such, around 70 percent of recently announced projects involve green hydrogen, while only 20 percent are blue hydrogen. Even though this interest in green hydrogen may help with developing electrolysis-based technologies, it may not be immediately effective for scaling regional clean hydrogen markets. Despite representing a relatively small share of the total, blue hydrogen projects account for nearly 95 percent of the capacity of the announced projects."

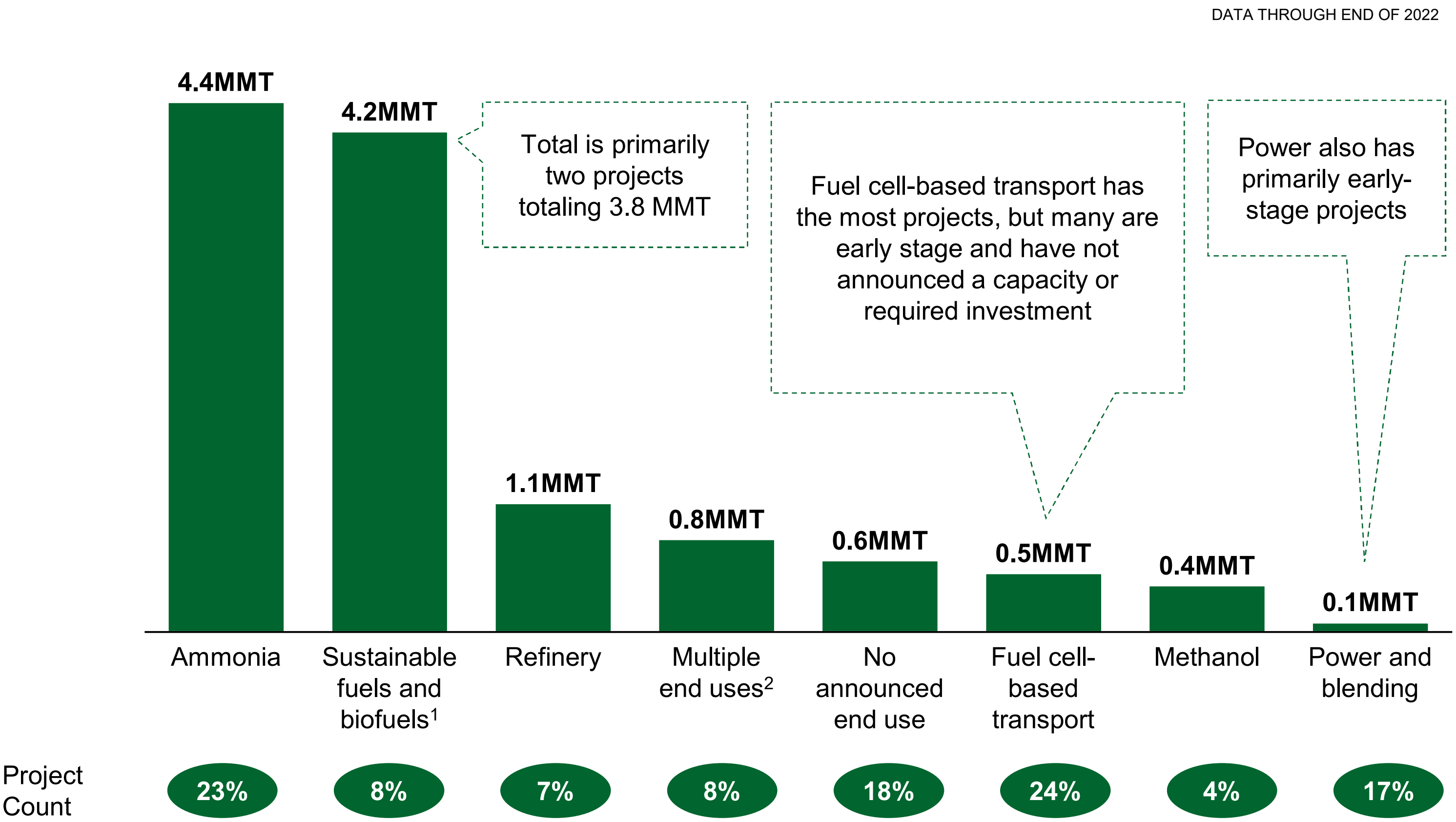
Figure 8: Currently announced clean hydrogen production projects would meet 2030 demand, with announcements accelerating – ~50% of total planned capacity was announced in 2022, although ~10.5 MMTpa of 12 MMTpa is still pre-final investment decision (FID). Tracker as of EOY 2022.

67 43% are electrolytic and 56% are reformation based. Note that many of these announced projects have not yet secured financing. See Chapter 3 for further details on investment dollars required to scale clean hydrogen. The near-term financing gap is greater in midstream and end-use infrastructure than in hydrogen production. If financed, announced projects to date cover ~50% of required investment in hydrogen production, but only ~25% of required end-use investment, and ~5% of distribution and storage infrastructure (Figure 16).

As part of a larger $8 billion hydrogen hub program funded through the Infrastructure Investment and Job, Regional Clean Hydrogen Hubs (H2Hubs) will help to address these challenges by creating networks of hydrogen producers, consumers, and shared local connective infrastructure.

Due to limited midstream infrastructure, announced hydrogen production projects to date have focused on offtakers that can be co-located with production as well as offtakers that already use carbon-intensive hydrogen. The largest announced offtakers are for ammonia, accelerated by export demand from Europe, and sustainable fuels and biofuels such as SAF, renewable diesel, and synthetic natural gas, driven by existing policy incentives such as the LCFS and RIN credits. With the PTC, lower production costs are possible, which could make best-in-class clean hydrogen projects cost-competitive with incumbent technologies within 3–5 years for many sectors (see Figure 15 and Figure 27 in Modeling Appendices), particularly if midstream and downstream investments are realized.

Announced U.S. clean hydrogen production projects by target end use sector, MMTpa



1 Includes sustainable fuels and biofuels and fuel-cell based transport
2 Represents production capacity that is targeting more than one of the other end use sectors
Source: McKinsey Hydrogen Insights P&I tracker & Electrolyzer supply tracker as of the end of 2022

Figure 9: Announced production projects are focused on sustainable fuels (~35%) – such as SAF, renewable diesel and renewable natural gas – and conversion consumers already using carbon-intensive hydrogen – ammonia (~35%) and refining (~10%) – which generally do not require large H2 midstream investments. Project announcement data as of the end of 2022.

Section 2.c: Techno-economies

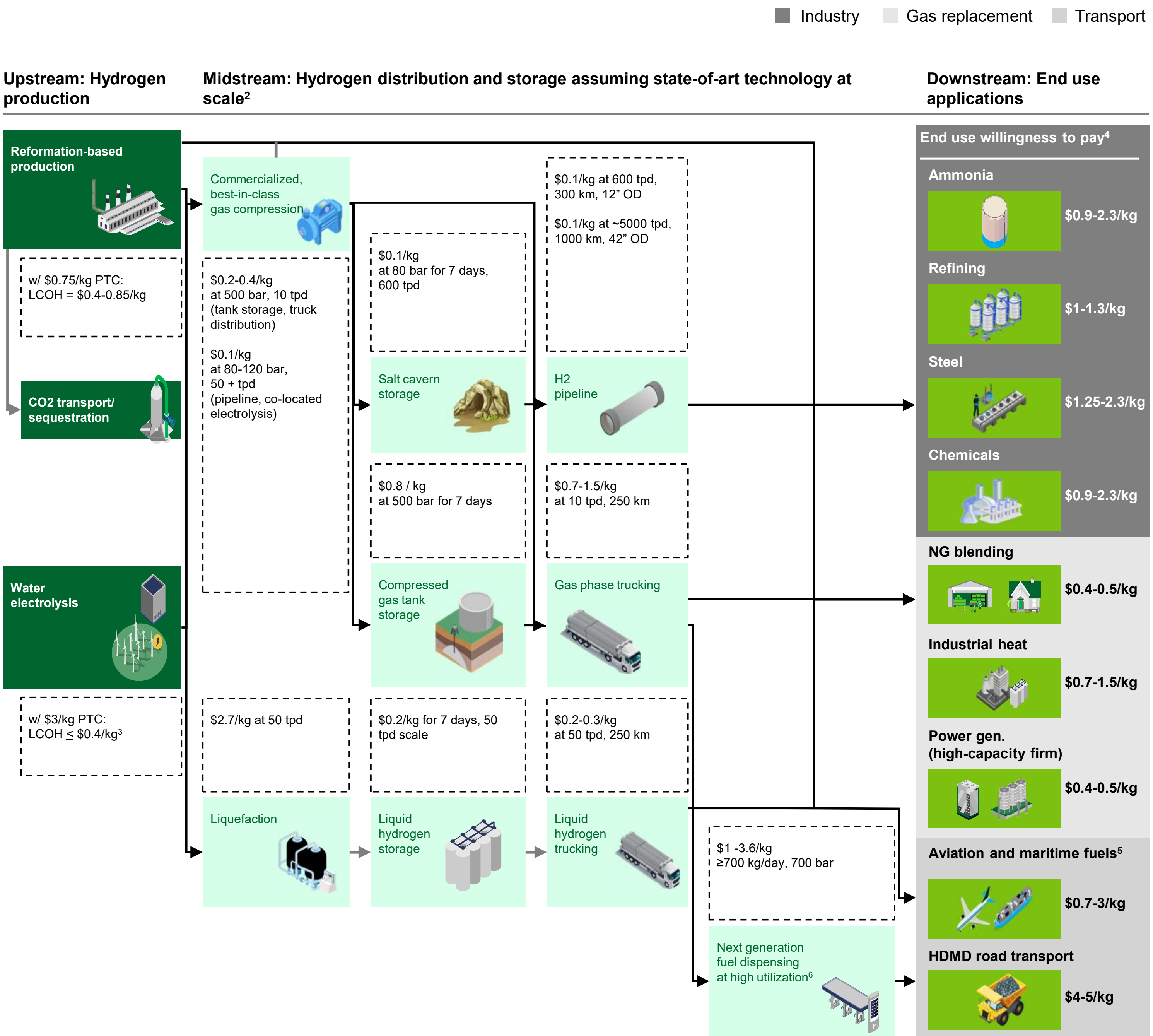
Key takeaways

- Even when hydrogen production costs are low, midstream and downstream costs can more than double the delivered price of hydrogen for some offtakers, particularly those using liquefaction for liquid hydrogen trucking and gas-phased trucking delivery systems (Figure 10).
- With the passage of the hydrogen PTC and associated cost learning, clean hydrogen from electrolysis becomes cost competitive, or approaches cost parity, with higher carbon-intensity production pathways (Figures 11, 12).

The delivered cost of hydrogen accounts for the full value chain—from upstream production to midstream distribution/storage to end-use equipment and infrastructure costs.

Even when hydrogen production costs are low, midstream, and downstream costs can more than double the price of hydrogen. Near-term, these cost differences can be especially large due to the required buildout of midstream infrastructure that may have low immediate utilization. As a result, in 2030, due to the PTC and cost declines through the 2020s, all end-use types are theoretically profitable for producers co-located with offtake or if salt caverns and pipelines are available. The profitability for other midstream pathways, such as gaseous and liquid distribution and storage, will be project and end-use dependent. Post-PTC expiration, end-uses with a low willingness to pay may also not be profitable for producers, even when production and demand are co-located. See Chapter 4 for additional details on production economics after PTC expiration.

2030 costs across the value chain if advances in distribution and storage technology are commercialized[1]



1 See appendix for calculation details
2 Data based on cost-downs shared from leading-edge companies who have deployed at demonstration scale (or larger)
3 Range based on varying renewables costs and electrolyzer sizes/technologies
4 Defined as the price an offtaker will pay for clean hydrogen
5 Represents delivery of hydrogen to aviation and maritime fuel production facilities
6 Greater than or equal to 70% utilization, assumes line fill at high pressure
Sources: HDSAM, Argonne National Laboratory; DOE National Hydrogen Strategy and Roadmap, Hydrogen Council

Figure 10: Industry-informed estimates of 2030 upstream and midstream costs. By 2030, industry estimates that multiple methods of hydrogen distribution and storage can become affordable if state-of-the-art technologies are commercialized at scale. Readers should sum (1) Upstream costs and (2) Midstream costs to arrive at a potential delivered cost of clean hydrogen, based on production pathway and storage/distribution method selected. Hydrogen production costs shown take an upper bound of production costs (~2MW (450 Nm3/h) PEM electrolyzer with Class 9 NREL ATB wind power) and then subtract the PTC at point-in-time. A wider range of LCOH values, without the PTC credit applied, are described in Figures 11 and 12.

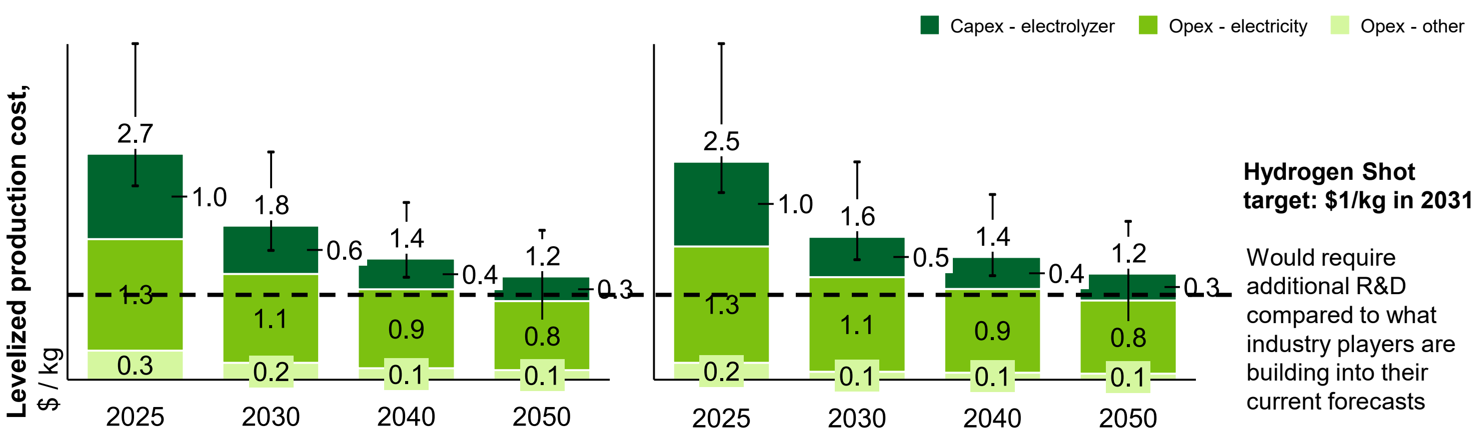
Upstream: With the passage of the hydrogen PTC and associated cost learning, clean hydrogen from electrolysis becomes cost competitive, or approaches cost parity, with more carbon-intensive production pathways (Figures 11 and 12) particularly post-2030. For reformation-based hydrogen, the cost of incorporating and operating CCS with new and existing facilities is covered by the longer-term certainty of the 45Q credit. Some electrolysis projects, which are expected to claim the full $3/kg PTC, can see their production costs reach zero within the next few years after applying the full production tax credit (Figure 11).

For water electrolysis, levelized production costs could decline by ~50% through 2030, driven by decreases in both electrolyzer capex costs and clean energy prices, as well as increased electrolyzer size.[68] As the industry moves down the cost curve, lower electrolyzer capex makes variable renewables for electrolysis more cost-effective. By 2030, clean energy prices account for more than 75% of the levelized production cost of hydrogen.

Electrolyzer capex is expected to fall due to (1) increases in production scale, (2) optimized and modularized system designs, and (3) improved stack designs to reduce material cost and increased power density. Electrolyzer learning rates are forecast at 9–17% per doubling of cumulative manufacturing volume and are conservative relative to learning rates demonstrated across other low-carbon technologies (e.g., solar PV and EV batteries).[69,xxx]

PEM electrolysis levelized hydrogen production cost (without PTC)[1,2,3], $/kg

Alkaline electrolysis levelized hydrogen production cost (without PTC)[1,4], $/kg



At equivalent production costs, delivered costs for electrolytic hydrogen will be higher than reformation-based hydrogen due to higher storage costs

1 These levelized costs use industry estimates for electrolyzer capex costs developed in 2020 using 2020 USD. Forecasted electrolyzer capex values are rapidly evolving and may differ between sources
2 Assumes ~18MW electrolyzer (4,000 Nm³/h) in 2025, ~90MW electrolyzer (20,000 Nm³/h) for 2030 onwards; electrolyzer installed capex: $900/kW (2025), $540/kW (2030), $350/kW (2040), $300/kW (2050); error bars also include reported LCOH values from Bloomberg New Energy Finance: $1.8/kg (2030), $0.7/kg (2050)
3 Assumes onshore wind power: Class 5 – Moderate (reference case), Class 1 – Moderate (low-cost case), Class 9 – Moderate (high-cost case); Class 1 – Moderate capacity factors: 51% (2025), 54% (2030), 55% (2040), 55% (2050); Class 5 – Moderate capacity factors: 44% (2025), 45% (2030), 46% (2040), 47% (2050); Class 9 – Moderate capacity factors: 28% (2025), 30% (2030), 31% (2040), 31% (2050); Class 1 – Moderate 4 LCOE: $22/MWh (2025), $18/MWh (2030), $16/MWh (2040), $15/MWh (2050); Class 5 – Moderate LCOE: $26/MWh (2025), $22/MWh (2030), $19/MWh (2040), $17/MWh (2050) Assumes ~18MW electrolyzer (4,000 Nm³/h) in 2025, ~90MW electrolyzer (20,000 Nm³/h) for 2030 onwards; electrolyzer installed capex: $850/kW (2025), $425/kW (2030), $350/kW (2040), $300/kW (2050); error bars also include reported LCOH values from Bloomberg New Energy Finance: $1.7/kg (2030), $0.6/kg (2050)
Source: NREL Annual Technology Baseline 2022, Hydrogen Council, Bloomberg New Energy Finance

Includes data from external sources – to be updated upon publication of DOE Working Group papers

Figure 11: Low-cost clean energy is the largest cost driver of hydrogen production costs and the primary lever to reach the Hydrogen Shot, however, the PTC removes near-term unit cost pressure, supporting liftoff as R&D advances are developed.

68 See Figure 2.
69 Percentage unit-cost reduction achieved per doubling of units produced

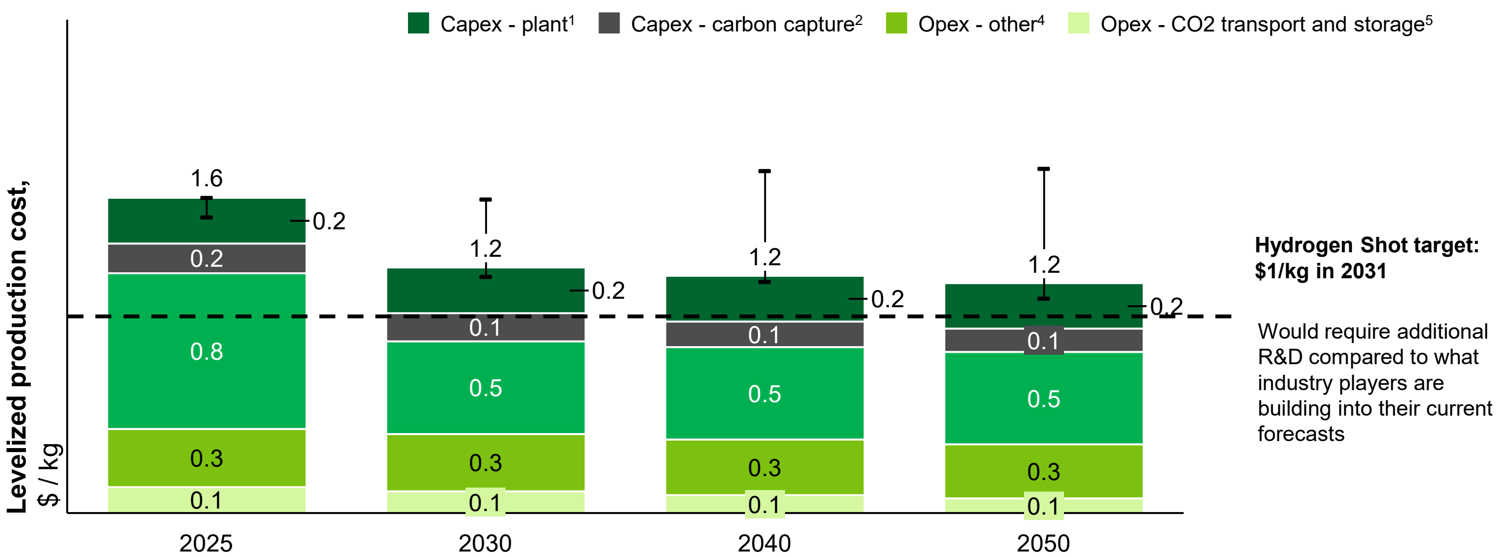
Reformation-based with CCS:

SMR- and ATR-based production pathways have already seen more significant learning curve cost-downs because the technologies are more mature. CCS, on the other hand, is just beginning to be deployed at scale. Moderate future cost reductions may be driven by:

- **Mature CCS technology produced in larger quantities** with greater modularization
- **New generations of CCS technology with higher performance** and/or lower cost
- **The switch to ATR facilities** (with similar long-term capex costs to SMRs) **with more concentrated CO2 gas** streams for lower cost capture and sequestration

The most significant cost uncertainty for reformation-based hydrogen is the price of natural gas, which represents ~50% of levelized production costs.

Levelized hydrogen production cost for SMR with >90% CCS (without PTC)[1], $/kg



1 These levelized costs use industry estimates for capex costs developed in 2020 using 2020 USD. Forecasted capex values may differ between sources
2 SMR facility capex (100k Nm^3/h capacity): $215 million (2025 onwards)
3 CCS capex (100k Nm^3/h capacity facility): $140 million (2025), $135 million (2030), $120 million (2040), $110 million (2050)
4 Natural gas reference case: $4.3 / MMBtu (2025), $3 / MMBtu (2030 onwards); assumes non-renewable natural gas; natural gas high case based on EIA Annual Energy Outlook 2022 high oil price scenario; natural gas low case based on EIA Annual Energy Outlook 2022 low oil price scenario
5 Includes O&M, catalyst replacement, electricity, and water costs
6 CO2 transport and storage: $48/tonne CO2 (2025), $44/tonne CO_2 (2030), $39/tonne CO2 (2040), $35/tonne CO2 (2050)
Source: Hydrogen Council, EIA Annual Energy Outlook 2022

Figure 12: Reformation-based H2 with CCS has a lower initial unsubsidized LCOH than electrolysis, but is expected to have limited cost-downs and is sensitive to natural gas prices.

Midstream

As clean hydrogen production costs fall toward the Hydrogen Shot target of $1 per kilogram, distribution and storage costs could represent much more than half of the delivered cost of clean hydrogen.[70] At low volumes and shorter distances, gaseous trucking transport has lower costs. Liquid-phase trucking becomes competitive at greater distances.
As the volume and distance of hydrogen flows increases, distribution costs will decline significantly with (1) full utilization of distribution networks and (2) sufficient pipeline deployment.

Downstream

Project developers, investors, and customers must decide between retrofitting existing infrastructure to use clean hydrogen or building new. These costs vary significantly by sector.

- **Ammonia and refining:** Clean hydrogen can be directly substituted for carbon-intensive hydrogen at ammonia production and refinery sites. Retrofits would be required to add carbon capture to existing steam methane reformers. Or, if electrolytic hydrogen production is selected instead of SMR with CCS, the plant may need further investments to replace steam provided by an SMR. Several ammonia producers along the U.S. Gulf Coast have announced carbon capture retrofits on existing facilities to decarbonize their hydrogen and access 45Q credits. While the costs of these retrofits vary, publicly reported data suggest costs of ~$130/tonne of ammonia production to add carbon capture[71], which could be paid off in < 5 years based on profits from 45Q credits.[xxi]

    - **Other industrial offtakers:** Outside of ammonia and oil-refining, industrial offtakers will require retrofits to their facilities beyond the addition of carbon capture to accommodate clean hydrogen. These retrofit requirements impact a variety of sectors such as methanol production and steel.[72] Future Liftoff reports may explore the specifics of these retrofits and associated economics, but they are not the focus of this report.

- **Transportation:** Transportation demand could drive a critical inflection point in the size of the domestic clean hydrogen market.

    For each use case and operating model (e.g., long-haul trucking), hydrogen must achieve break-even on a total cost of ownership (TCO) basis with incumbent technology and with other decarbonization options (e.g., battery electric vehicles).

    Fuel-cell-based transportation currently faces cost hurdles in hydrogen distribution, compression, and refueling stations that meaningfully increase the total delivered cost of hydrogen. As fleets begin to transition to clean hydrogen, a reinforcing feedback loop could occur in which improved hydrogen infrastructure catalyzes more FCEV production, and thus – more FCEV production leads to lower cost vehicles, more customer demand, and more widely scaled, lower-cost hydrogen infrastructure.

    For some types of hydrogen-derivative fuels (e.g., ammonia or methanol for maritime uses), additional infrastructure requirements can add significant levelized cost (e.g., dedicated refueling and operational infrastructure for bunkering).

70 Note $1/kg by 2030 is an R&D target that would require production cost-downs outside of marginal returns to scale
71 Based on publicly available data for CCS retrofit costs of CF Industries ammonia production facility in Donaldsonville, LA (source)
72 Note that up to 30% of natural gas (by volume) can be replaced with hydrogen for DRI-EAF without significant retrofits (source)

- **Industrial Heating:** Some applications may require equipment changes for industrial heat owing to a higher volume of hydrogen being required to produce the same heat.

- **Gas replacement:** Retrofitting a turbine to accommodate hydrogen blending can cost up to $25M for a 100MW gas plant, depending on the blending level.[xxii] Most of the cost is for plant upgrades to offload, process, and pipe hydrogen through the plant. It is likely that as the cost of hydrogen and fuel cells moves down, hydrogen could become an economic option for low-carbon low-capacity factor power, and for resilience events such as polar vortexes. Fuel cell cost-downs and hydrogen turbine retrofits for older plants and retiring plants will result in very low capex, allowing more economic operation for resiliency-focused plants that only operate 5-10% of the year. For these retrofits, multiple private companies have announced commercially ready turbines that can be fired on hydrogen / natural gas blends with a path to 100% hydrogen combustion.

Chapter 3: Pathways to Commercial Scale

The U.S. hydrogen market is expected to evolve over multiple phases, each characterized by a combination of new end-uses reaching commercial viability, the maturation of domestic demand, and the expansion of midstream infrastructure:

1) **Near-term expansion (~2023–2026):** Clean hydrogen is expected to replace today's carbon-intensive hydrogen, particularly in industrial/chemicals use cases including ammonia and oil refining. Many of these replacement projects will be financed from corporate balance sheets with extensions of corporate debt or from investor syndicates offering market-rate terms. In parallel, government programs will help de-risk FOAK/NOAK projects in more nascent upstream, midstream, and end-use applications, including through loans, grants, and DOE Hydrogen Hubs.[73]

2) **Industrial scaling (~2027–2034):** Build-out of new midstream infrastructure will reduce the delivered cost of hydrogen to improve the business case for more nascent end-use applications (e.g., fuel cell-based transportation).

    - When co-location isn't available, liquid or gaseous-phase hydrogen trucking is likely to be the primary mode of distributing hydrogen through at least 2030 (see Chapter 2a for discussion of trade-offs between gaseous and liquid trucking), at which point local demand volumes may start to justify construction of dedicated hydrogen distribution pipelines, or in limited cases the retrofitting of existing infrastructure.
    - On the financing side, project finance debt from commercial banks will play an increasingly important role, as risks related to revenue (e.g., offtake volumes, price volatility) are mitigated through private contracts (e.g., guaranteed offtakes, hedges) and risks related to uncertainty in project performance are mitigated through public-sector-facilitated demonstrations (e.g., via the DOE's Regional Clean Hydrogen Hubs program) and beyond.[74]

(3) Long-term growth (~2035+): A self-sustaining commercial market needs to develop prior to the sunset of the PTC (new projects built after 2032) — one in which clean hydrogen is competitive for numerous end-uses and is financed almost exclusively by private capital providers offering market-rate terms. Achieving cost reductions prior to credit expiration will ensure the bankability of additional hydrogen infrastructure projects. This evolution would be driven by falling production costs dependent on:

A. The availability of low-cost, clean electricity

B. Equipment cost declines for electrolysis or CCS

C. Reliable and at-scale hydrogen storage[75]

D. The development of highly utilized hydrogen distribution networks including dedicated hydrogen pipelines

73 Clean hydrogen hubs will create networks of hydrogen producers, consumers, and local connective infrastructure to accelerate the use of hydrogen as a clean energy carrier that can deliver or store tremendous amounts of energy.
74 The Office of Clean Energy Demonstrations (OCED) was established in December 2021 as part of the Bipartisan Infrastructure Law to accelerate clean energy technologies from the lab to market and fill a critical innovation gap on the path to achieving our nation's climate goals of net zero emissions by 2050. OCED's mission is to deliver clean energy demonstration projects at scale in partnership with the private sector to accelerate deployment, market adoption, and the equitable transition to a decarbonized energy system
75 In the absence of pipelines

By 2050, the domestic hydrogen market could reach up to 27–80 MMTpa (Figure 13), consistent with *The U.S. Long-Term Strategy*.[76,xxiii] Market size will be dependent on the pace of cost declines across the value chain, clean energy build-out and cost (for water electrolysis), and the price of competitive or enabling decarbonization levers like electrification and carbon capture.

Transportation and industrial/chemical segments are expected to make up >90% of total hydrogen demand by 2050 – with clean ammonia, methanol, fuel cell-based road transportation, biofuels, and synfuels for aviation driving most of this volume.[77]

Figures 13.1 and 13.2 illustrate different potential demand scenarios for the US clean hydrogen market:

- Scenario (A) illustrates the DOE National Clean Hydrogen Strategy and Roadmap business-as-usual (BAU) case where, today through 2030, clean hydrogen demand is only partially realized across ammonia and oil refining use cases. 2040 and 2050 potential demand represents the low-end of estimates for long-term clean hydrogen use across sectors like fuel-cell based transportation and power-to-liquid fuels.

- Scenario (B) describes the base-case of the DOE National Clean Hydrogen Strategy and Roadmap, in which ammonia and oil refining transition at least partially, and potentially fully, to clean hydrogen by 2030.[78] In 2040, the size of the fuel cell-based transport opportunity is the same across Scenarios (A) and (B), while Scenario (B) shows additional demand for clean hydrogen in sectors like energy storage (2040, 2050) and greater opportunities in biofuels and power-to-liquid fuels (in 2050).

- Scenario (C) describes the high case from the DOE National Clean Hydrogen Strategy. Near-term, oil refining and ammonia fully transition to clean hydrogen. 2040 demand is higher than Scenario (B) due to additional demand from fuel-cell based transport, biofuels, and industrial opportunities such as steel. See Figure 13.2 which discusses a potential additional ~2 MMTpa of clean hydrogen demand in the power sector in 2030 to meet Clean Grid 2035 targets.

- Scenario (D) illustrates a hydrogen 'spike case' from the McKinsey Global Energy Perspective. This scenario forecasts a near-term market (to 2030) twice as large as those scenarios modeled in the DOE National Clean Hydrogen Strategy (~10 MMTpa vs. ~20 MMTpa by 2030) – reflecting a view that many uses come online in parallel rather than in sequence. In addition, this scenario forecasts greater demand from sectors including fuel cell-based transport, aviation fuels, heating, and industrial uses like steel in 2040 and 2050 compared to all DOE scenarios (A – C). This scenario also illustrates
near-term demand for hydrogen in the power sector (while the PTC is active) that falls in 2040 and 2050 as other decarbonization technologies see cost learning (e.g., LDES, DAC) and the PTC expires.

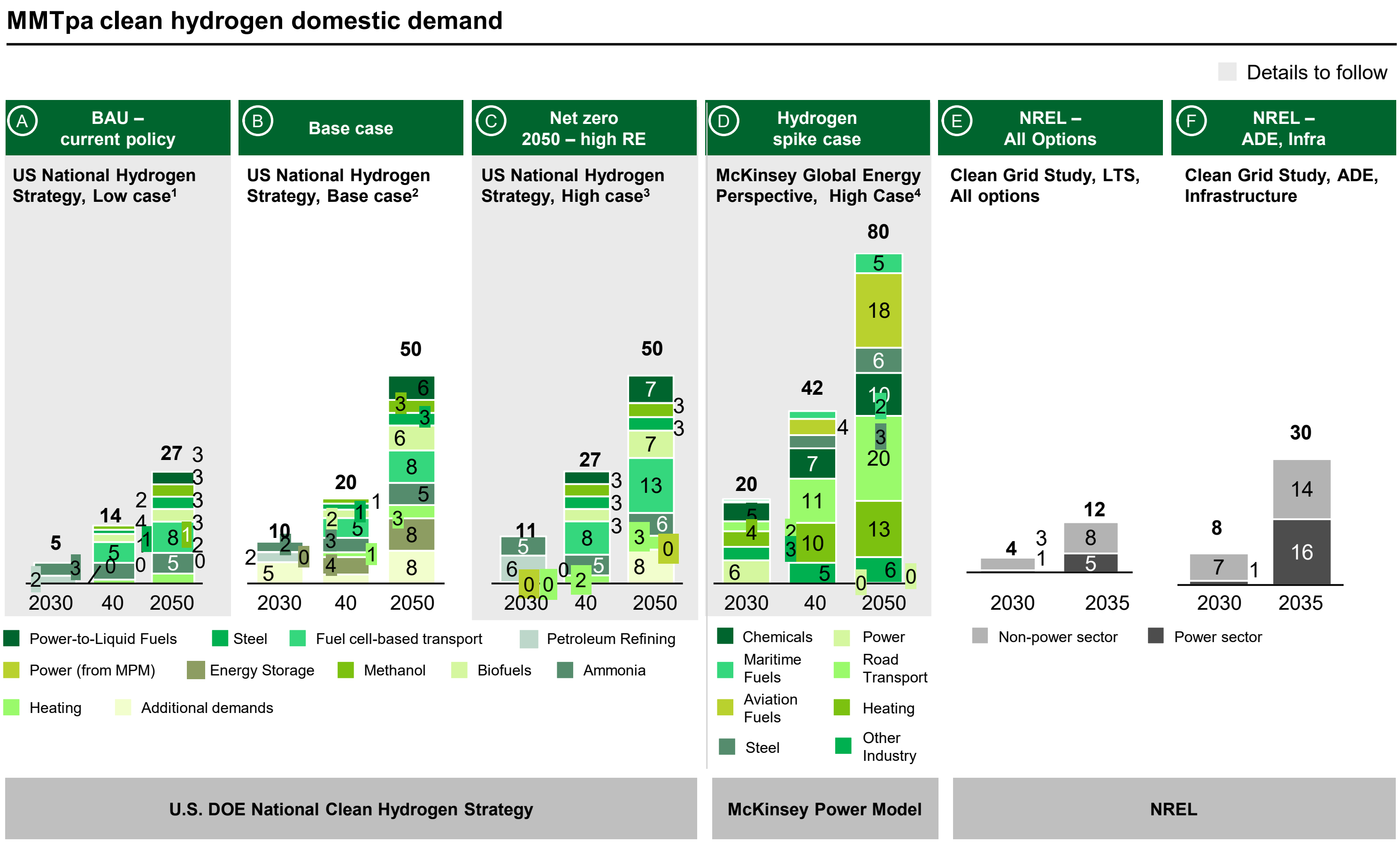
In the scenarios modeled in this report, clean hydrogen has a more limited role in some gas replacement use cases (high-capacity firm power, residential and commercial heating) unless other technologies (e.g., LDES, DAC, scaled storage for CCS) fail to see cost learning. In that case, near the end of the PTC-term there could be expanded opportunities for hydrogen's cost-effective use in the power sector (see Scenarios E, F). And, long-term, clean hydrogen could be an option for long duration energy storage for seasonal use cases (see Scenarios B, C). As noted above, modeling done for this Liftoff report does not incorporate the potential for hydrogen combustion in the power sector in non-baseload applications.

76 Scenarios are consistent with the U.S. DOE National Clean Hydrogen Strategy and Roadmap which forecasts approximately ~50 MMTpa of domestic hydrogen demand by 2050
77 2050 ranges based on BAU. Current policy case and Net zero 2050 high RE case: Ammonia: 5–5.5 MMTpa; Methanol: 3–3.3 MMTpa; Biofuels: 3–6.6 MMTpa; Fuel cell-based road transportation: 7.5–13.2 MMTpa; Synfuels for aviation: 3–6.6 MMTpa
78 In the U.S. DOE National Clean Hydrogen Strategy 'Base Case' scenario, ammonia and oil refining transition at least partially to clean hydrogen (~2 MMTpa by 2030, respectively, for each sector). And, may fully transition to clean hydrogen (~5 MMTpa by 2030 of 'Additional demands' – which could be made up entirely from ammonia/oil refining demand, or from other more nascent market segments activating by 2030). Other current, emerging, and future markets with higher ranges of uncertainty today, such as hydrogen exports, power-to-liquid fuels, and petroleum refining could generate additional demand.

In addition, policy goals and decarbonization incentives could drive additional uptake of clean hydrogen in the power sector. The NREL Clean Grid 2035 scenarios illustrate one such example:

- Scenario (E) evaluates hydrogen demand for power and non-power-sector use cases in 2030 and 2035. In the NREL "All Options" scenario, cost and performance of all decarbonization technologies improves, including direct air capture, which becomes cost competitive under this scenario.[79] There is potential for ~4 MMTpa of clean hydrogen domestic demand in 2030 (less 2030 demand than Scenarios A – D) and ~12 MMTpa in 2035, including ~5 MMTpa in the power sector.

- In Scenario F, the NREL "Infrastructure" case assumes transmission technologies improve and new permitting/siting allows for greater levels of transmission deployment. In this scenario, low-cost transport and storage for hydrogen, CCS, and biomass is available while DAC is not. Non-power sector demand for clean hydrogen is much higher in this scenario in 2030, as is power and non-power sector demands for clean hydrogen in 2035.[80]

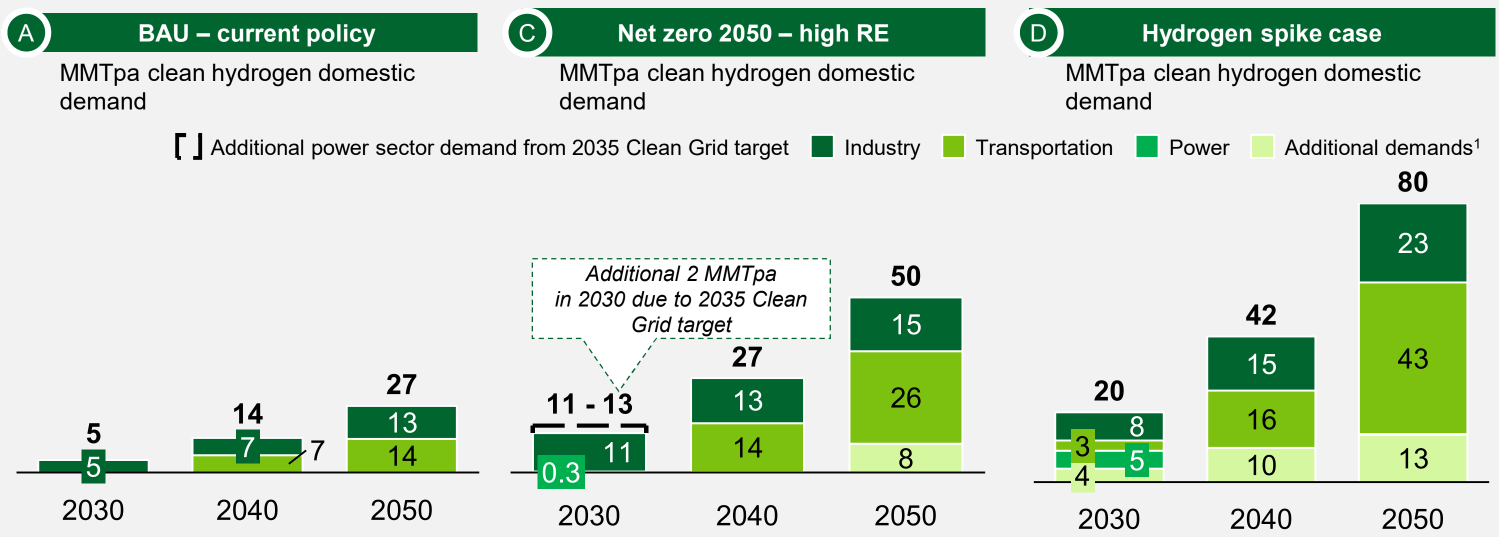


1 Based on low end of ranges for end use demand in National Hydrogen Strategy & Roadmap, with the McKinsey Power Model (MPM) demand for Power sector to enable consistency across Liftoff reports
2 Based on the base case directly taken from the National Hydrogen Strategy & Roadmap
3 Based on high end of ranges for end use demand in National Hydrogen Strategy & Roadmap, with the McKinsey Power Model (MPM) demand for Power sector to enable consistency across Liftoff reports
4 Assumes additional ramp up in policy support for decarbonization

Figure 13.1: Forecasts regarding the pace and scale of hydrogen vary, particularly in the long-term (2050). Most models agree Industrial uses will drive demand through 2030 and that Transport is a critical national inflection point.

79 Denholm, Paul, Patrick Brown, Wesley Cole, et al. 2022. Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. Golden, CO: National Renewable Energy Laboratory. NREL/TP6A40-81644. https://www.nrel.gov/docs/fy22osti/81644.pdf
80 Denholm, Paul, Patrick Brown, Wesley Cole, et al. 2022. Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. Golden, CO: National Renewable Energy Laboratory. NREL/TP6A40-81644. https://www.nrel.gov/docs/fy22osti/81644.pdf

Sidebar to Figure 13:



Includes the IRA and assumes that, despite the additional funding for clean hydrogen, the current commercialization challenges are not overcome, holding back industry growth

Ammonia and oil refining drive demand through 2030 with significant growth in fuel cell-based road transport post-2030

Includes the IRA and assumes that the expansion of the hydrogen industry advances in line with a net zero by 2050 economy unconstrained by renewables deployment

Ammonia and oil refining completely transition to clean hydrogen by 2030 and post-2030 fuel-cell based road transport and aviation demand accelerates more rapidly

Includes the IRA and assumes that clean hydrogen technologies advance more quickly than other decarbonization technologies – particularly LDES and CCUS, causing increased demand from all end uses

Increased 2030 power sector demand due to IRA incentives combined with slower LDES and CCUS development

1 Includes residential and commercial heating as well as potential additional clean hydrogen demand that could come from increased uptake in new and existing end uses (e.g., hydrogen fuel cells for backup power)
Source: : DOE National Clean Hydrogen Strategy and Roadmap (BAU – current policy and Net zero 2050 – high RE scenarios); McKinsey Global Energy Perspective 2022, Achieved Commitments Scenario (Hydrogen spike case), McKinsey Power Model

Figure 13.2: Summary of scenarios A, C, and D to ease reading. Models related to capital formation, energy jobs, and the split of electrolytic vs. reformation-based hydrogen production pathways follow scenario (C) from the model above.

Figure 13.2 illustrates a roll-up/simplified view of some scenarios shown in Figure 13.1. In addition, Scenario (C) in Figure 13.2 shows the potential for ~2 MMTpa additional demand in 2030 if Clean Grid 2035 targets drove additional uptake of clean hydrogen in the power sector while the PTC is active. This could increase near-term (2030) demand from 11 MMTpa to up to 13 MMtpa in 2030 (see dotted line in Scenario C – Figure 13.2).

Section 3.a: Dynamics impacting pathways to commercial scale

Key takeaways

- Transportation and industrial segments are expected to make up >90% of total hydrogen demand by 2050 – with clean ammonia, methanol, biofuels, fuel cell-based road transportation and synfuels for aviation driving the majority of this volume (Figure 13, above).

- The near-term project economics for clean hydrogen production projects depends on several key drivers across the value chain including: (1) Availability of low-cost feedstocks; (2) Availability of geologic storage; (3) Colocation of production with offtake; (4) Offtakers' willingness to pay.

- If cheap, clean electricity is available, electrolysis and reformation with CCS will account for roughly equal production share by 2050. If clean electricity deployment is constrained, reformation with CCS could dominate (Figure 14 – both clean energy deployment and CCS infrastructure face potential challenges to scale such as land use restrictions and permitting challenges that could impact the split of electrolytic vs. reformation-based production).

- When evaluating best-in-class projects, the PTC pulls forward breakeven for clean hydrogen versus traditional, fossil alternatives to within 3-5 years for many end uses (Figure 15). However, these breakeven points are sensitive to future fossil fuel prices and the levelized cost and capacity factors of clean power sources. The breakeven point for use cases under a lower-than-expected future fossil fuel price scenario or in regions with poor renewables performance could be delayed (see Figure 27 in Modeling Appendices).

By 2025, with the hydrogen PTC, costs of clean hydrogen production with the hydrogen PTC will be below expected end-user willingness to pay for many projects.[81]

For example, with the $3/kg PTC, projects selling hydrogen to co-located ammonia manufacturers could see returns on equity as high as 50% near the end of the PTC term.[82] These returns will be spread across the value chain, potentially accruing to players with leverage in constrained parts of the value chain such as project developers, electrolyzer manufacturers, EPCs with hydrogen experience, and offtakers. Returns stated below do not include assumptions on how margins will be distributed across the value chain. The balance of first-mover advantage of prime production and distribution locations will compete against capex declines for fast followers, resulting in a dynamic deployment for efficient capital.

The near-term project economics for clean hydrogen production projects depend on several key drivers across the value chain:

- **Availability of low-cost feedstocks:** electricity represents the largest share of electrolysis costs (up to 2/3 by 2050, see Figure 11), so a low levelized cost of electricity has a significant effect on production costs and project returns – a 15% increase in electricity costs can reduce returns 3-5%. Constrained clean power build out can also limit the deployment of electrolyzers. Similarly, natural gas prices can affect project returns for reformation-based hydrogen, although the share of the cost stack is smaller.

81 Note, in the absence of cost-effective midstream infrastructure, the delivered cost of hydrogen can be much higher than the levelized cost of hydrogen (see Figure 10)
82 Illustrative only - IRR conditions are for modeled scenarios under specific set of assumptions and are not applicable across all project types, sites, and more. Please see Modeling Appendices for further detail. Investors should perform their own scenario analysis to evaluate return profile of a particular investment.

- **Availability of geologic storage:** Industrial offtakers, such as ammonia and oil refining facilities, expect stable offtake volumes so electrolysis powered by variable renewables will need storage to smooth production volumes. Levelized costs of geologic storage are 4-10x lower than compressed gas storage (see Figure 6) and are conducive to large scale storage, acting as an enabler for electrolytic hydrogen.

- **Co-location of production with offtake:** In the absence of midstream infrastructure, such as dedicated hydrogen pipelines, co-location can eliminate the need for costly gaseous- or liquid-phase truck distribution, which can significantly increase the delivered cost of hydrogen (for one example, see Figure 10). This increased cost from hydrogen liquid or gas-phase trucking could make some end-uses non-economic even with the PTC (see section 2c).

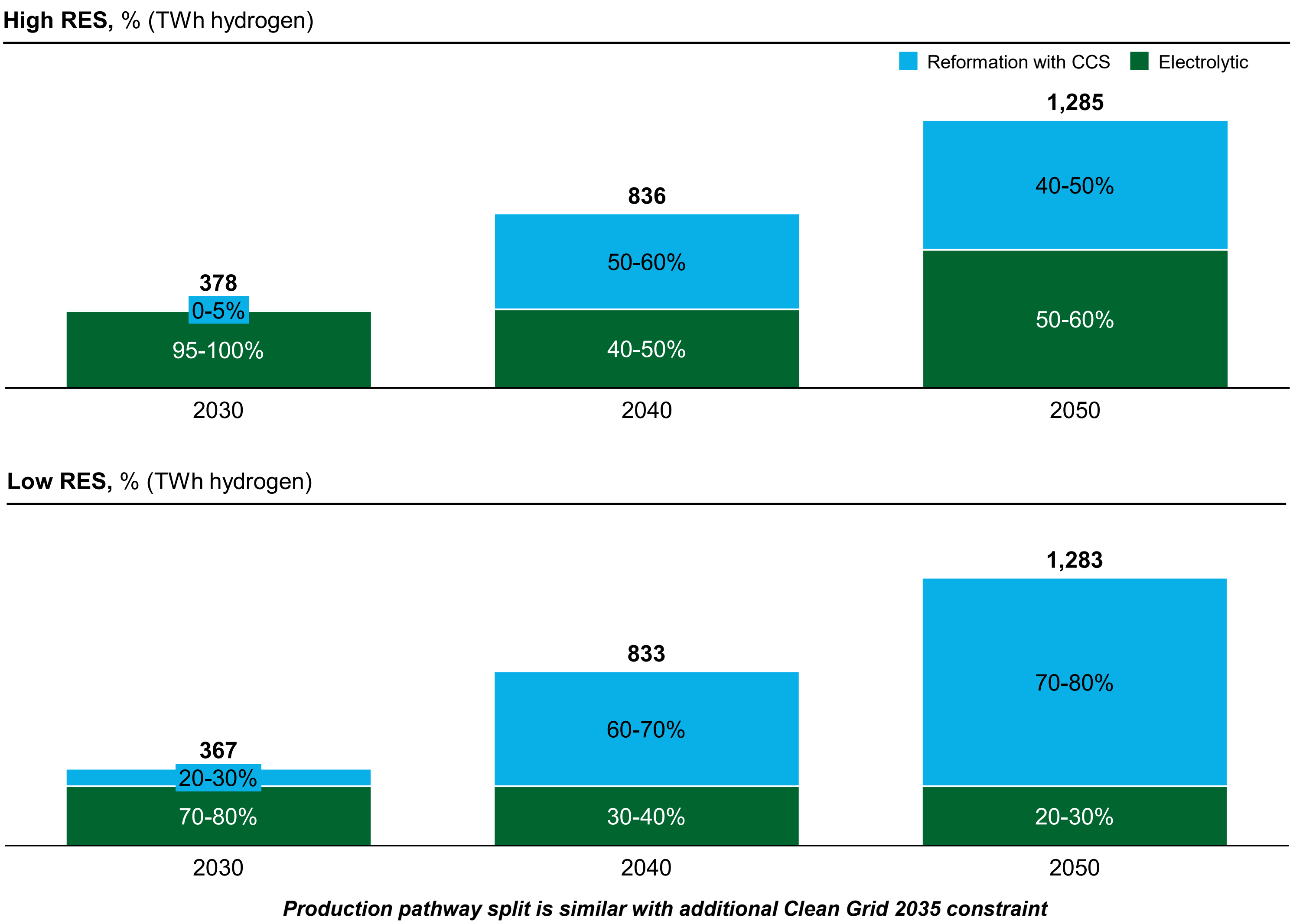
- **Offtakers' willingness to pay:** Both the price offtakers will pay and their willingness to commit to long-term offtake are critical for clean hydrogen production project economics. The willingness to commit to long-term offtake enables low-cost debt-based project financing, which both improves returns and accelerates liftoff (see Chapter 4). While production projects co-located with offtake are profitable during the PTC term, offtaker willingness to pay directly affects the degree of profitability during the credit term (PTC active) as well as whether a production project is profitable post-PTC expiration.

After projects have received the PTC for 10 years, clean hydrogen production project economics and operations will shift significantly. Depending on offtaker willingness to pay, asset owners may choose to run existing electrolyzers at lower utilization during low marginal power costs.

Production

Multiple technologies will be used to produce clean hydrogen in the U.S. For both electrolysis-based and reformation-based production pathways, feedstock cost (e.g., clean power or natural gas) is the critical driver of project economics. If cheap, clean electricity is available, electrolysis and reformation with CCS will account for roughly equal production share by 2050 (Figure 14). If clean electricity deployment is constrained by challenges such as land use restrictions or siting/permitting bottlenecks, modeling results show reformation with CCS will dominate. Note that reformation with CCS is likely to face a separate set of siting/permitting bottlenecks, including permitting CO2 storage sites such as Class VI wells. Off-grid wind and solar for water electrolysis will also avoid facing potential interconnection delays experienced by grid-connected systems.

Split of production pathways over time for high & low renewable energy source (RES) deployment scenarios



Source: McKinsey Power Model

Figure 14: H2 PTC is expected to drive accelerated electrolysis build out, while reformation with CCS build out primarily occurs post-PTC expiration and may become dominant if clean energy availability is constrained.

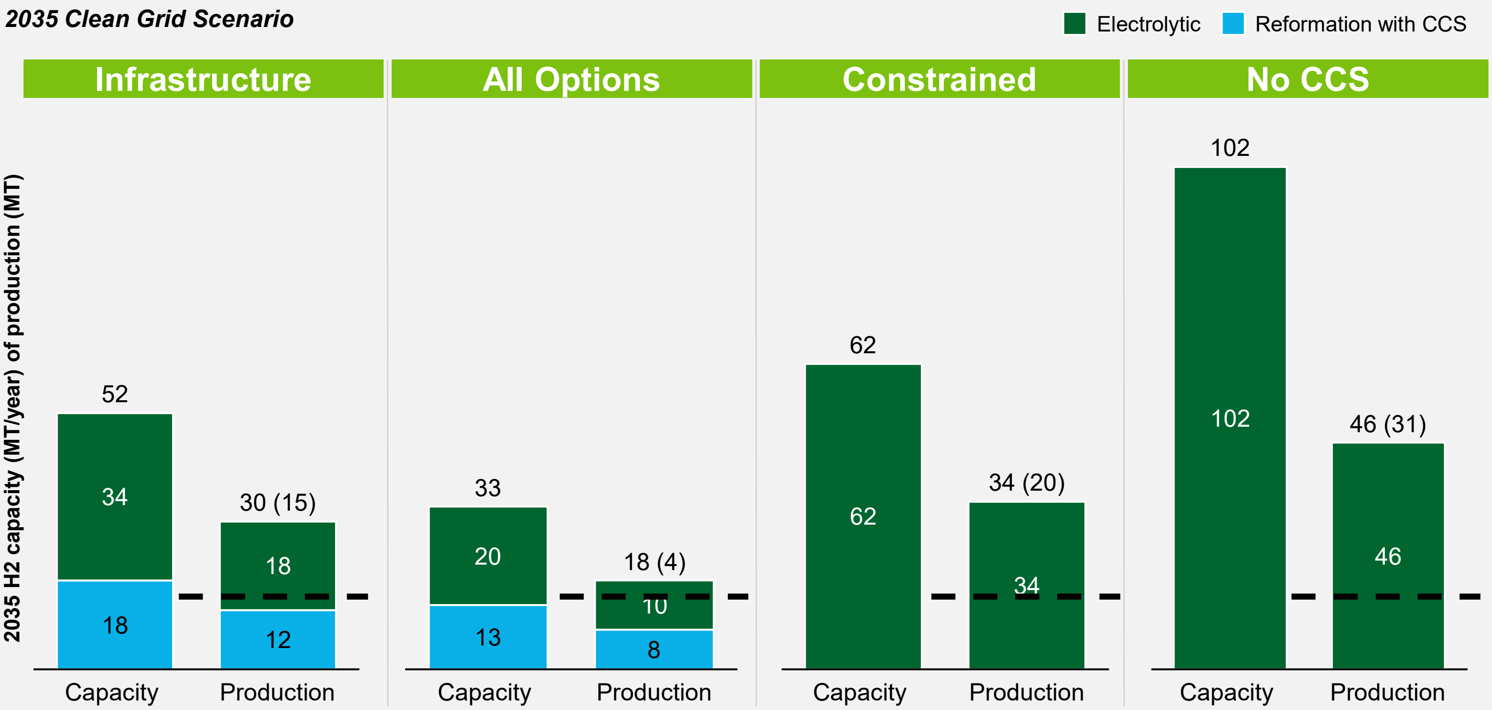
Notably, in both scenarios, electrolytic hydrogen dominates in the near-term, with 70–80% share even in the low-RES case, driven by the value in the hydrogen PTC. Since grid interconnection is one of the major challenges with renewables deployment, the ability of hydrogen to use off-grid RES makes it yet more competitive when competing for scarce RES projects even post-PTC expiration. Note that off-grid renewable hydrogen production lends itself to gaseous transport since liquid value chains struggle and add significant expense with variable power supply.[83]

83 Liquefiers can only turn down ~20% and don't work well with on-off duty cycles—batteries and hydrogen storage are required for off-grid liquefiers connected to variable renewable energy

Sidebar to Figure 14:

The NREL Clean Grid 2035 study offers an alternative view of the potential split of production pathways in a single year (2035). The left bar in each scenario represents production capacity (MT/year if running at full output), and the right bar provides actual production (MT). Numbers at the top of each bar indicate the total hydrogen capacity or production, with the values in parentheses specifying the total production used for the power sector.[84]

Sources of hydrogen fuel production (ADE demand case) shows the potentially important role of electrolysis in 2035



Source: NREL C2035 Clean Grid study

Midstream

Midstream distribution and storage are a significant part of the cost stack, as described in Chapter 2. Co-location of production and offtake can decrease distribution costs and increase hydrogen production project returns by up to 3–5%.[85] However, co-location can also increase storage costs and is not always possible given local resources (e.g., availability of clean power near electrolysis site, proximity to carbon sequestration to reformation site).

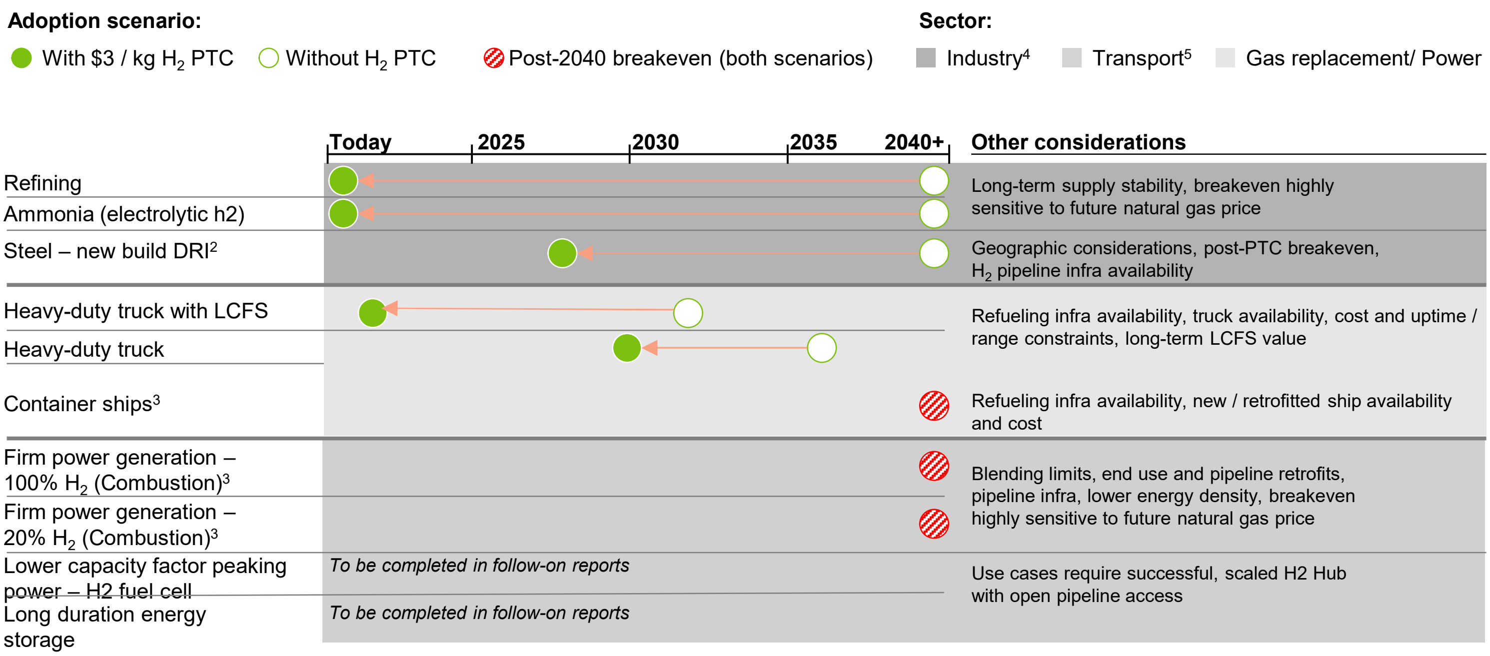
Transport applications will also require the build-out of additional midstream infrastructure including refueling stations for FCEVs and bunkering infrastructure for marine use cases. Distribution costs account for most of the delivered cost of hydrogen for these end-uses.

84 Denholm, Paul, Patrick Brown, Wesley Cole, et al. 2022. Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. Golden, CO: National Renewable Energy Laboratory. NREL/TP6A40-81644. https://www.nrel.gov/docs/fy22osti/81644.pdf
85 Example: clean hydrogen produced ~100 km from an ammonia offtaker and distributed using gas phase trucking at 500 bar yields 3–5% lower returns compared to production co-located with the ammonia plant. See Modeling Appendices.

End-uses

The hydrogen PTC brings forward total cost of ownership breakeven, so that best-in-class clean hydrogen projects are economically competitive within the next 3 to 5 years across a variety of sectors (Figure 15 – best-in-class includes projects with access to favorable renewables to maintain a low LCOH). However, other enablers beyond theoretical economic breakeven are required for widespread adoption, such as low-cost enabling infrastructure (to reduce not just the production, but the delivered cost of hydrogen), long-term supply stability, and/or regulatory drivers. These breakeven points are also sensitive to future fossil fuel prices and the levelized cost and capacity factors of clean power sources. The breakeven point for use cases under a lower-than-expected future fossil fuel price scenario or in regions with poor renewables performance will be delayed (see Figure 27 in Modeling Appendix).

Breakeven timing for hydrogen vs. conventional alternative[1]



1 Assumes 'average" hydrogen production from electrolysis and $3/kg PTC; assumes a production cost floor of $0.40/kg. No carbon pricing for business as usual
2 Within 5% of breakeven during PTC term, but costs do not cross. Once the PTC sunsets, TCO is >5% of breakeven. Breakeven timing shown as the mid-point of the PTC term.
3 Use cases do not breakeven without additional carbon tax, higher willingness to pay, or lower H2 cost floor
4 Assuming hydrogen production is co-located with demand, avoiding distribution costs
5 Assumes 300km between hydrogen production and refueling station
Source: Hydrogen Council, McKinsey Hydrogen Insights Analysis

Best-in-class refers to projects in areas with favorable renewables (e.g., NREL ATB Class 1 Wind); less competitive projects will have a later breakeven timeline. Appendix Figure 27 shows these ranges.

Figure 15: When evaluating best-in-class projects, industry forecasts estimate that the PTC pulls forward breakeven for clean hydrogen versus traditional, fossil alternatives to within 3-5 years for most end uses. However, many offtakers may hesitate to switch to clean hydrogen given uncertainty over pace of hydrogen supply scale up, switching costs, performance, and lack of cost-effective mid- and downstream infrastructure. Existing and new regulatory drivers may help to overcome these challenges.

These TCOs were developed using industry input data from the Hydrogen Council and calculated considering the PTC-driven reductions in hydrogen feedstock costs. When these TCOs were compared to other DOE publications that did not incorporate the PTC, a five-year breakeven acceleration was seen, consistent with the analyses in this report.[86]

86 Based on forthcoming U.S. Department of Energy Vehicles Technology Office (VTO) and Hydrogen and Fuel Cell Technologies Office (HFTO) publication

Industry:

Ammonia and refining

With the PTC, the production costs from electrolysis and reformation with CCS are immediately more cost competitive than the production cost at existing SMR facilities without CCS when production is co-located with refining and ammonia offtakers (see Figure 15). The ammonia sector also has established markets and distribution infrastructure already available, enabling near-term adoption. The main challenge for these offtakers to switch to clean hydrogen is confidence in the long-term supply of clean hydrogen (if hydrogen production is not integrated in the ammonia/refinery facility or co-owned). Existing ammonia production facilities with integrated reformation-based hydrogen production will also need to weigh carbon capture retrofit feasibility and costs against the PTC and 45Q credit values. For ammonia, the breakeven point is also highly dependent on the price of natural gas.

Producing clean hydrogen for ammonia has potential returns of 15–25%, which could reach 45–50% with electrolytic hydrogen for projects built just before the end of the PTC term—not accounting for margin distribution across the value chain, which will reduce project developers' IRRs as described above.[87]

Other industry, including steel

Other end-uses which are not yet economic for clean hydrogen, such as steel production via DRI-EAF, may reach economic break-even soon, but must still overcome infrastructure challenges and incur additional costs to receive and use hydrogen. For example, if low-cost hydrogen cannot be produced near industrial uses—due to poor renewable power potential or carbon sequestration resources near the offtaker—costly midstream infrastructure could prevent projects from being built. Specific end-uses, such as DRI-EAF steelmaking with hydrogen, require very reliable and high-volume supply due to high utilization requirements. This demand, in turn, requires a reliable supply base across multiple suppliers and pipeline infrastructure, which may not be in place given upfront cost and coordination challenges even if the lifetime economics are theoretically favorable.

Transportation:

Road Transport: Fuel-cell electric vehicles (e.g., city buses, heavy-duty trucks)

After industrial end-uses, road transport end-uses such as heavy-duty trucks powered by hydrogen fuel cells are among the next set of end-uses to reach economic break even (see Figure 15). These end-uses are advantaged by having among the highest willingness to pay ($4-5/kg).[iii] However, hydrogen is not a "drop-in" solution for these end-uses, presenting both economic and non-economic challenges to overcome. The two primary challenges for hydrogen uptake are (1) the cost and logistics of building refueling infrastructure at scale and (2) developing and scaling fuel cell vehicles themselves (e.g., improving fuel cell durability in the vehicle). For these reasons, demand of hydrogen for transportation is expected to continue to accelerate post-2030 as these challenges are overcome. Existing and new regulatory drivers may also help to overcome address some of these challenges, just as state and federal programs helped to scale BEVs in the early days of commercial liftoff.

As these challenges are addressed, road transport end-uses are expected to expand first in markets with additional sector-specific credits, such as the Low Carbon Fuel Standard (LCFS).[88] In these markets, despite currently high refueling infrastructure costs, hydrogen technologies are expected to be cost-competitive in the near future and could be adopted on a limited basis by early adopters

87 Illustrative only - IRRs are for modeled scenarios under specific set of assumptions and are not applicable across all project types, sites, and more. Please see Modeling Appendices for further detail. Investors should perform their own scenario analysis to evaluate return profile of a particular investment.
88 Only available in CA, WA, and OR at present

Based on the high willingness to pay, if adoption challenges can be overcome, producers can also earn strong returns selling to road transport end-uses starting at 20–25% and reaching 55–60% for production projects built just before the PTC sunset, (not accounting for margin distribution across the value chain, which will reduce project developers' IRRs, as described above). These returns are highly sensitive to the cost of refueling infrastructure and diesel prices. Diesel prices evolving based on EIA's low or high oil price scenarios would respectively decrease or increase IRRs by 10 percentage points.[89]

Gas Replacement – Power:

Combustion of pure hydrogen and hydrogen/natural gas blends in combined-cycle gas turbines (CCGTs) run as high-capacity factor firm power generation resources is, in many instances, not expected to be cost competitive against natural gas combustion in CCGTs with CCS, particularly in the near-term. However, some regions may still see hydrogen combustion when decision making is based on factors other than the lowest cost nationally available solutions such as local constraints on CCS (e.g., if priorities dictate a carbon-free grid as CCS is not fully carbon free) or for resiliency uses in decarbonized gas microgrids. Alternatively, hydrogen combustion may be deployed within a hub where highly utilized distribution infrastructure already exists, reducing hydrogen transport and storage costs. A number of projects are already exploring use cases for hydrogen combustion, including public announcements across multiple regions.[90]

Hydrogen and hydrogen blends can also be combusted for lower-capacity factor power. The economics of these use cases were not analyzed in this iteration of the Liftoff report.

Hydrogen fuel cells may also have a role in power generation for low-capacity peaking power, but adoption is dependent on either capex cost declines (installed fuel cell capex needs to fall below $450/kW to make peaking use cases economic) or improvements in fuel cell durability.[91] Retrofits of retiring plants to include hydrogen combustion turbines may prove to be extremely cost-effective at well below installed capex of $450/kW but retrofits can be asset-specific and these costs are not explored in this report. Such examples would provide opportunities for capex sensitive low-utilization cases of peaking or grid resiliency. Additional policy driving the electricity system towards higher levels of decarbonization could lead to shifts in hydrogen's applicability within the power sector.[92]

A net-zero grid requirement could result in low or negative cost variable renewable power to store in many regions. Open-access hydrogen hubs powered by the Infrastructure Investment and Jobs Act (IIJA) could create an opportunity to store that power as hydrogen. Open access for pipeline transport and storage of hydrogen is the key trigger to enable low-cost hydrogen energy storage for long duration and for resilience events. Associated cost-downs from IIJA and IRA could lead to sub $550/kW electrolysis and sub $450/kW fuel cell power stations by 2030.[93] Assuming a wind farm with 40% capacity factor can allow 10% uptime with curtailed power, $0.01/kWh cost of the curtailed power, and 5% use of the associated fuel cell power station for resilience events, levelized cost of power would be ~$0.25/kWh for hydrogen[94]. This compares to a ~$0.37/kWh for gas combustion with a high-utilization DAC system, and much higher cost with combined cycle plants with CCUS and low utilization; in a net-zero grid, hydrogen in a successful hub could beat fossil power for resilience events. As a result, an open-access H2Hub in a region with net-zero grid requirements could likely use hydrogen for long term and seasonal storage for otherwise curtailed power.

91 Hunter, C. A., Penev, M. M., Reznicek, E. P., Eichman, J., Rustagi, N., & Baldwin, S. F. (2021). Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids. Joule, 5(8), 2077-2101. doi:10.1016/j.joule.2021.06.018
92 A 100% clean electricity system is defined as one with zero net greenhouse gas emissions
93 Hunter, C. A., Penev, M. M., Reznicek, E. P., Eichman, J., Rustagi, N., & Baldwin, S. F. (2021). Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids. Joule, 5(8), 2077-2101. doi:10.1016/j.joule.2021.06.018
94 Using H2FAST with parameters for 2035 fuel cell equipment costs from this report, EIA data on costs of combustion turbines with criteria emission controls, DAC costs from the pathways report, and combined cycle with CCUS costs from H2FAST

Compared to long duration energy storage (LDES), round trip efficiency is on par near ~50% for both, power capex is much lower for hydrogen at a projected sub $650/kW compared to ~$1100 - 1400/kW for best-in-class LDES, and long-term storage costs are much lower at $2/kWh in an open-access hub with pipelines and storage vs $8/kwh for LDES.[95] As a result, a successful hydrogen hub could allow for the lowest cost storage at sites with significant curtailed energy in a net-zero power grid.

Section 3.b: Capital Requirements

Key takeaways

- $85 – 215B of cumulative investment is required to scale the domestic hydrogen economy through 2030. As much as ~half of the investment required will be for midstream or end-use infrastructure. Another ~third will be for net new clean energy production (Figure 16).

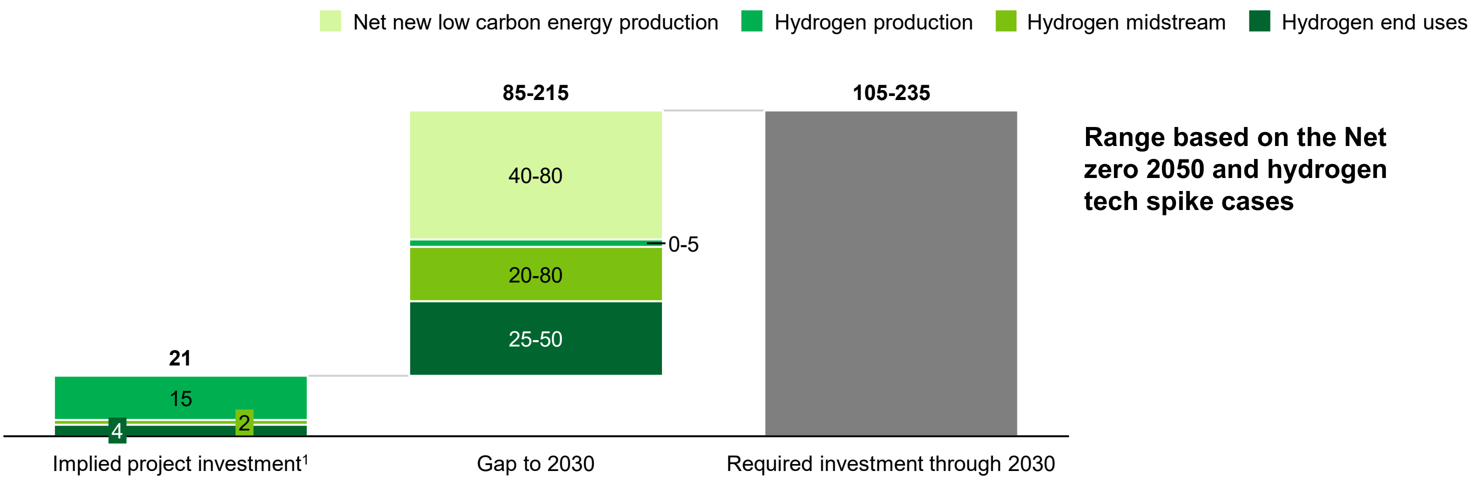
- The hydrogen PTC has kick-started domestic production, and investment dollars have followed. Midstream and end-use infrastructure investments face a more acute financing gap. As of January 2023, announced clean hydrogen production projects that have reached the feasibility study stage represent ~$15B in planned investment, while all midstream and end-use investment represents ~$6B.

Growing the U.S. clean hydrogen economy to over 10 MMTpa by 2030 and 50 MMTpa by 2050 requires:

- **$85–215B of cumulative investment** into hydrogen across the U.S. by 2030, and
- **$800–1,100B cumulative** by 2050[96]

These investments will be spread along the value chain, with roughly half required for midstream and end-use infrastructure (e.g., pipelines, storage, refueling stations) and half to one-third required for net new clean energy production for water electrolysis (Figure 16).

Investments into hydrogen value chain, $ B



1 Excludes pre-feasibility study production projects
Source: Hydrogen Council, McKinsey Hydrogen Investment Model

Figure 16: Announced hydrogen production investments are on track to meet 2030 requirements if projects pass final investment decision. However, an $85–215B capital gap exists across midstream (distribution, storage) and end-use infrastructure, low carbon energy production.

95 Hunter et al, "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids", Joule (2021)

96 Investment values in 2020 dollars. See Modeling Appendix for Figure 16 calculation details. Range is based on the Net zero 2050 – high RE and hydrogen spike case demand scenarios shown in Figure 13.

There are numerous types of private sector capital providers that will support this advancement at varying stages of the value chain and at varying levels of technology and market maturity, as described in the Pathways to Commercial Liftoff: Introduction.

- **The hydrogen PTC has kick-started domestic production, and investment dollars have followed. Midstream and end-use infrastructure investments face a more acute financing gap**. As of December 2022, announced clean hydrogen production projects that have reached the feasibility study stage represent ~$15B in planned investment, while all midstream and end-use investment represents ~$6B. If production projects secure financing, announcements would cover almost all of the 2030 production investment requirements.[97] In contrast, project announcements only cover ~25% of required end-use and ~5% of distribution and storage infrastructure needs (Figure 16). IIJA H2Hubs funding from both government and private sector will provide at least an additional $16B in projects with balanced production, distribution, and offtake. 2030 to 2050, midstream and end-use infrastructure are expected to account for >80% of required investment as adoption of distributed hydrogen use cases accelerates and more dispersed distribution/storage networks are built.

- **Production: Upstream projects have the most immediate investment requirements, starting at $1.5–2B/year (today–2030) and declining to $0.5–1B/year from 2030 to 2050.** Declines are attributed to reductions in capital costs to stand-up a facility, closing the manufacturing gap (e.g., for domestic electrolyzer production), and changing production mix towards a higher share of reformation-based hydrogen with CCS after PTC sunset (see Figure 14). Clean hydrogen production projects that require more than $10–20 million in financing will need to tap debt markets to lower their cost of capital.

  To date, most announced production projects have been funded by large corporates who are decarbonizing their own value chain or see an opportunity to expand into hydrogen as an adjacent business (via a combination of equity and corporate balance sheet debt). Private equity investors are also beginning to invest in hydrogen production. Compared to many clean energy technologies, hydrogen production has a high technology readiness level (TRL) and existing market pull (e.g., from high carbon intensity industrial uses). However, project finance and widespread commercial debt for hydrogen production has been held back due to uncertainty in long-term offtake. At present, many proposed projects lack a committed and credit-worthy high volume hydrogen buyer.

  In addition, investors need to see a handful of domestic production projects operating at full, scaled throughput in order to collect sufficient engineering and performance data to evaluate bankability. Investors have noted they are also waiting to better understand forthcoming regulatory guidance domestically and abroad, project economics and repeatability, and progress along the hydrogen cost curve as the market matures and projects prove business model stability (i.e., to unlock additional debt finance).

  Significant capital will also be required to kick-start domestic electrolyzer manufacturing. Corporate balance sheets are expected to be the primary equity pool that funds near-term electrolyzer scale-up, including from large OEMs and smaller, pure-play suppliers and producers in the upstream market, with some participation from growth equity investors.

97 Note that proposed investment dollars may see significant attrition – not all projects will make it from feasibility study through to FEED, permitting, procurement, and final construction

- **Midstream investment requirements ramp-up after 2030 from \$2–3B/year to \$15–20B/year 2030–2050, as more distributed end-uses like road transportation adopt clean hydrogen and local hubs/regional networks are linked by pipeline into a national network.**[98] Near-term, local storage and regional distribution infrastructure are expected to develop around hydrogen hubs/infrastructure clusters, funded through a mix of public and private capital. Scaled midstream projects are complicated because they often require coordination of nodes at both ends of the network - production and offtake - as well as complex siting and permitting that can extend through multiple jurisdictions.

  In the case of hydrogen, investors cite near-term uncertainty about the make-up of regional hydrogen infrastructure, including the format and scale of distribution (e.g., which types of hydrogen distribution will become standard, the volume of hydrogen that will be transported over long distances via pipeline vs. trucking). Near-term, infrastructure investors with experience owning or operating sophisticated assets (e.g., LNG pipelines) are actively pursuing some midstream projects, often with the expectation that early developments will require some form of public sector support (e.g., guarantees to buy-down production or offtake risk). As the domestic clean hydrogen market matures, the hydrogen market will see lower reliance on these types of public supports and additional pools of capital are expected to enter the market (e.g., from investors with experience in adjacent asset classes such as utilities or oil and gas).

- **Downstream investment requirements increase from \$3–4B/year for end-uses with low switching costs that transition to clean hydrogen in the near-term, to \$10–15B/year after 2030 as end-uses with higher switching costs adopt clean hydrogen.**[99] Initially, corporations already using reformation-based hydrogen are likely to be the dominant capital providers for clean hydrogen use at their own facilities (i.e., refineries and ammonia producers retrofit existing steam methane reformers with CCS, supported by bank financing, tax equity providers, off their own balance sheets, and by potential government financing). Private equity funds are also investing in offtake segments with high relative technology maturity and with a path to revenue within a PE deal lifecycle. However, some of these capital flows are concentrated outside of the U.S. where demand-side policies, particularly in Europe, have given investors confidence in the market value of low carbon-intensity commodities. Domestically, investors have favored end-use investments in industrial applications (short-term) and SAFs (medium-term). Short-term, industrial applications already show hydrogen demand (many use hydrogen today) and can often co-locate production and offtake. Medium-term, SAFs are an end-use sector with high willingness to pay in a category where some midstream infrastructure costs could be lower (SAFs are drop-in fuels). Some funds have expressed reticence about the hurdles to scaling hydrogen in mobility applications or have noted they are waiting longer to see that market develop (e.g., vehicle cost-downs, abundance of refueling stations, major fleets taking FID on fuel FCEVs).

Section 3.c: Broader implications of hydrogen scale-up

Key takeaways

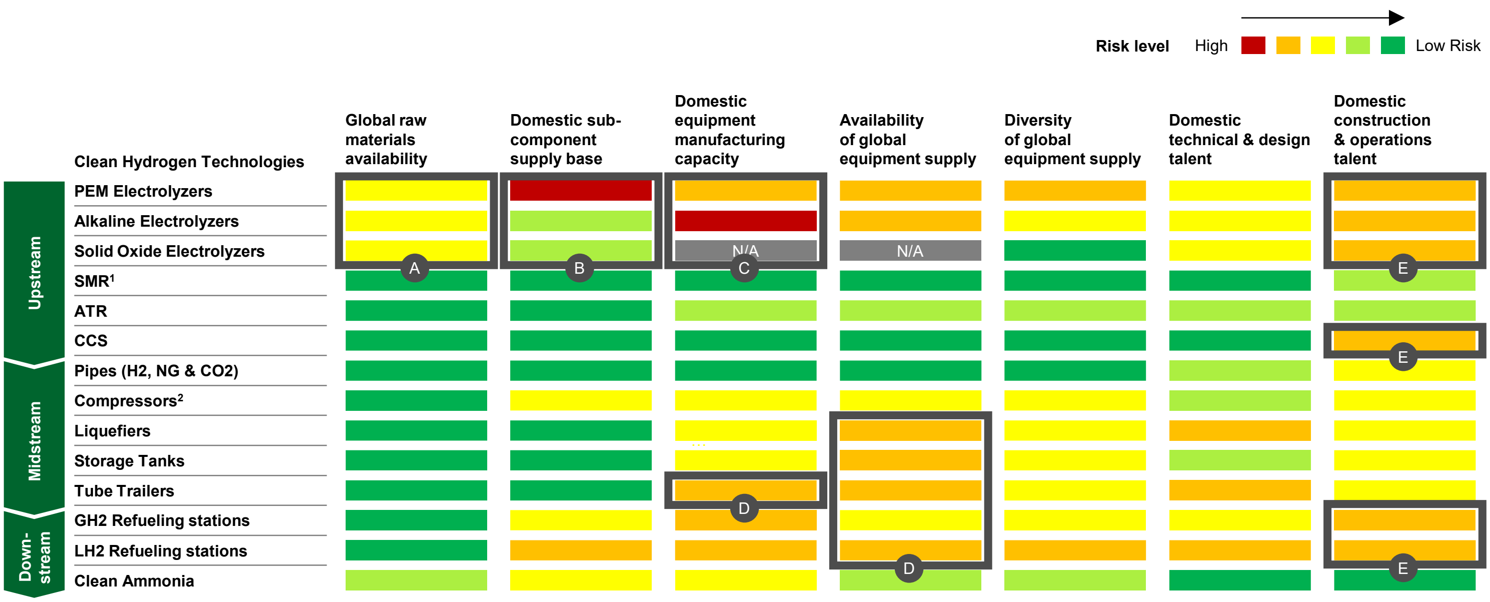
- There are five areas of emerging near-term supply chain risk (Figure 17): (A) Availability of raw materials for electrolyzer manufacturing; (B) Availability of suppliers, and timeline for qualification, of precision manufactured sub-components for electrolyzers; (C) Scale of production facilities for electrolyzer assembly (Figure 18); (D) U.S.-based production capacity for hydrogen-specific midstream infrastructure; (E) Availability of EPC providers with hydrogen capabilities.
- Based on industry estimates, the hydrogen economy can create ~100,000 net new direct and indirect jobs related to new hydrogen infrastructure build out in 2030 (~450,000 cumulative job-years through 2030), with an additional ~120,000 direct and indirect jobs in 2030 related to the operations and maintenance of hydrogen assets (Figure 19).

98 See Modeling Appendix for description of methodology for calculating required investments
99 See Modeling Appendix for description of methodology for calculating required investments

Supply chain

To scale the clean hydrogen market from <1 MMTpa today to 50 MMTpa by 2050, ~5x the size of the carbon-intensive hydrogen market today, the entire clean hydrogen supply chain must scale rapidly, representing a significant opportunity as domestic and international markets mature. Electrolyzers, tube trailers and hydrogen storage tanks, and EPCs to guide project construction need to scale. Like many decarbonization technologies, electrolytic hydrogen also depends on further securing and scaling the supply chain for clean energy.[100] There are five areas of emerging near-term supply chain challenges, discussed below (Figure 17).

Potential supply chain vulnerabilities, 2025



1: Includes large scale compressors at industrial and productions sites and compressors at refueling facilities | 2: No significant additional build out of Steam Methane Reformers anticipated
Source: Department of Energy Fuel Cells & Electrolyzers Supply Chain Report, ENS Interviews, NREL experts

Figure 17: Electrolysis will be challenged by supply-chain constraints in both raw materials and equipment manufacturing capacity during a critical scale-up period through 2025 in addition to challenges with renewables build-out and sourcing a domestic workforce. If electrolysis fails to scale during the PTC time horizon, it may not achieve sufficient cost downs prior to PTC expiration. However, if supply chain constraints do develop, the fact that there are several different types of electrolyzers that require different raw materials may provide opportunities to work around those constraints.

A. Availability of raw materials for electrolyzer manufacturing:

Reliance on foreign raw material suppliers could impact the growth of US-based PEM electrolyzer manufacturing. PEM electrolyzers account for ~30% of global deployed electrolyzers (by capacity) but are expected to play an outsized role in the U.S. (40-45% of announced electrolysis capacity) due to more U.S.-based PEM electrolyzer manufacturers vs. the rest of the world.[101] To meet the demands of a growing hydrogen market, large increases in the extraction and refining of many materials will be needed. PEM electrolyzers require raw materials, including catalysts, that are currently addressed primarily (and often exclusively) by imports. The DOE Fuel Cells & Electrolyzers Supply Chain Report identifies lanthanum, yttrium, and iridium as the raw materials of lower relative abundance and with mines more likely to be located outside the United States. By 2030, U.S. PEM electrolyzer demand could require ~15–30% of global iridium raw material production (depending on the PEM vs Alkaline deployment rate).[102]

100 See DOE analysis on solar, wind, and nuclear supply chains
101 Based on McKinsey Hydrogen Insights P&I tracker and electrolyzer supply tracker as of the end of 2022
102 See Modeling Appendix for methodology for calculating iridium requirements

Over 80% of iridium supply comes from South Africa, with almost no opportunity for domestic production. The mix of electrolyzer technologies deployed, electrolyzer iridium recycling requirements, and R&D to reduce platinum group metal (PGM) requirements, can help address this challenge as electrolyzer supply chains continue to rapidly scale. As of Q1 2022, the United States appears to have sufficient resources and supply chains for many of the other key materials required, including stainless steel, titanium, zirconium, and nickel.[103]

In addition, PEM electrolyzers require PFAS ionomers – widely used, long lasting chemicals, components of which break down very slowly over time.[104] PFAS use is being phased out in the EU. In the United States, the EPA has proposed listing several PFAS chemicals as hazardous materials under the Comprehensive Environmental Response, Compensation and Liability Act, requiring reporting PFAS use in the Toxics Release Inventory and is exploring other regulatory levers and analytics, that consider the complete life cycle, including associated emissions during productions and disposal while respecting the need for essential fluoropolymer products. As such, electrolyzer manufacturers have noted that domestic manufacturing for PFAS could slow, bottlenecking availability of this critical component.[105] At present, there is no technology pathway to switch away from PFAS use in PEM electrolyzers (efforts |to build alternative membranes have not met durability/performance standards). If PEM raw materials challenges are not met, other electrolyzer technologies (e.g., alkaline) will represent a larger share of the electrolyzer mix in the U.S. As illustrated in Figure 3, as a variety of electrolyzer technologies reach commercial viability, there will be reduced reliance on a single design or value chain to meet the needs of the growing clean hydrogen market.

B. Availability of suppliers, and timeline for qualification, of precision manufactured sub-components for electrolyzers:

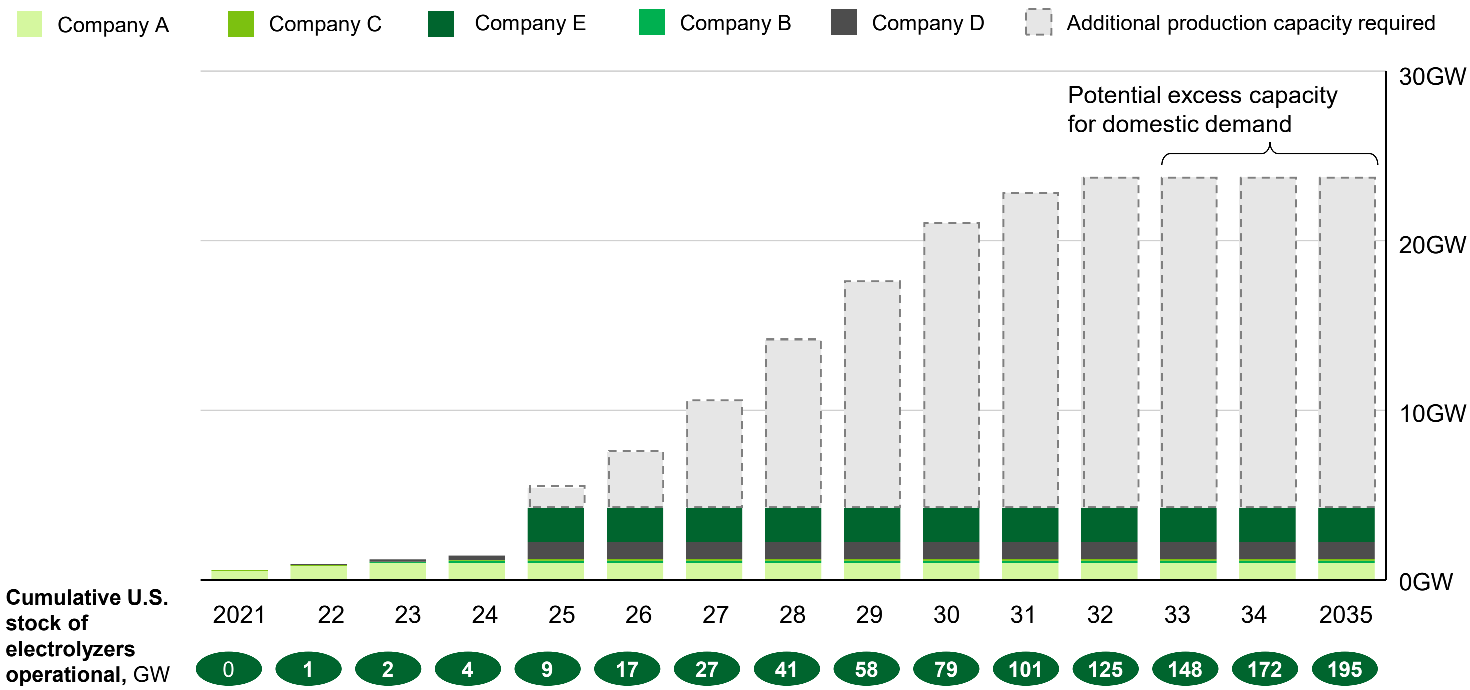
The demand for electrolyzer components is likely to significantly exceed supply globally until electrolyzer production expands. As is common with manufacturing scale-up, the associated supply base will take time to grow due to lead times on components that require precision manufacturing with long manufacturer qualification periods (e.g., the membrane electrode assembly containing the catalyst and membrane layers). Today, the U.S. relies on foreign suppliers with limited domestic options, though the international partners that currently support these components include countries with a strong and positive U.S. trade relationship..

C. Scale of production facilities for electrolyzer assembly:

To enable deployment of ~100 GW of operational electrolyzers by 2030, domestic production would need to scale from 4 GW of publicly announced capacity with target commercial operation dates (CODs) to as much as ~20–25 GW p.a. by 2030.[106] In some instances, hydrogen producers today are already being quoted lead times of 2 to 3 years when they order electrolyzers. If the size of U.S. production facilities increases to match EU facility sizes,[107] the U.S. could require as much as ~12–14 additional electrolyzer production facilities by 2030 (Figure 18, which represents a potential high case for domestic production if all 2030 electrolytic hydrogen demand was met with domestically-produced electrolyzers). These facilities could employ ~20,000 workers in aggregate.[108] The ramp -up to meet 2030 demand may lead to an electrolyzer manufacturing capacity overbuild in the 2030s, but this may be mitigated by opportunities for electrolyzer export (not explored in this report).

103 US Department of Energy. (n.d.). Water Electrolyzers and Fuel Cells Supply Chain: Supply Chain Deep Dive Assessment . Retrieved March 17, 2023, from https://www.energy.gov/sites/default/files/2022-02/Fuel%20Cells%20%26%20Electrolyzers%20Supply%20Chain%20Report%20-%20Final.pdf
104 per- and polyfluoroalkyl substances
105 Efforts to build an alternative, hydrocarbon membrane to replace PFAS ionomers have been largely unsuccessful due to problems w/ durability/performance.
106 Additional 1 GW/year facility has been announced, but does not yet have a COD (source)
107 U.S. facility sizes are currently an average of 0.7GW/facility, while EU facilities are on average 1.5GW/facility. Data is from the Hydrogen Council and McKinsey's Hydrogen Insights Electrolyzer and Fuel Cell OEM Supply Tracker
|108 Assuming approximately 800 employees required per 1GW/year of production facility (source)

Publicly announced (EOY '22) & required U.S. electrolyzer production capacity, GW/year



Data as EOY 2022. Only includes publicly announced projects that have shared launch date.

20 – 25 GW of electrolyzer capacity by 2030 represents an upper bound on domestic production (assumes ~10 MMTpa all produced by electrolytic hydrogen using domestically-manufactured electrolyzers).

Note: Assumes 100% of U.S. electrolyzer production is dedicated to U.S. projects, without imports, data updated through the end of 2022. The capacity ramp up curve shown here is based on producing ~10 MMT clean hydrogen from electrolysis by 2030, based on Figure 13 and Figure 14 (in the Net Zero 2050 – high RE hydrogen demand scenario shown in (Fig 13, Scenario B) and the electrolysis vs. reformation production split shown in Figure 14 – with all needs met via domestic electrolyzer manufacturing).
1 Assumes each firm is confined to a single manufacturing site per country
2 Based on press releases – e.g., Plug Power 0.5GW facility in NY supports 380 jobs
3 Missing Production assume each new factory requires 3 years to reach peak performance (40%/70%/100%)

Figure 18: Electrolyzer production capacity needs to ramp quickly to meet projected PTC-driven spike in electrolyzer demand through the early 2030s. A near-term steep ramp-up could create risk of under-utilized plants in the 2030s if export markets are not available. Data as of the end of 2022.

D. U.S.-based production capacity for hydrogen-specific midstream infrastructure:

As described above, hydrogen trucking will likely represent the majority of hydrogen distribution in the near- and mid-term for distributed end-uses such as transportation. On the other hand, power sector and industrial applications are more likely to be co-located or connected via a pipeline and are thus likely to have lower delivery costs. For more distributed use cases, U.S. tube trailer manufacturing is currently in the low 100 units p.a. with lead times exceeding a year. Scale-up must address issues with carbon fiber costs used in new tube trailers and supplies as well as manufacturing techniques (e.g., high quality carbon fiber products). Similarly, other midstream components such as hydrogen-specific balance of plant mechanisms (e.g., compressors, storage tanks, liquefiers, valves, hoses) must scale rapidly. These components do not face significant scale-up constraints beyond the cost to build manufacturing capacity, so are less challenging to address compared to the required ramp in electrolyzer manufacturing.

E. Availability of EPC providers with hydrogen capabilities:

EPC providers will need specialized experience, sufficient workforce, and established contract structures for hydrogen production and refueling projects. The U.S. does not currently have a sufficient, appropriately skilled workforce to manufacture, construct, or operate the volume of hydrogen infrastructure required to meet projected demand, so scaling this workforce presents both a challenge and an opportunity. Skillsets across both gas handling and electrical systems management will be required. Labor in adjacent industries such as oil and gas should be mobilized to fill roles ranging from hydrogen production and pipeline construction to operations and maintenance, often in different areas of the country than current talent pool locations (e.g., remote regions with high renewables potential). Jobs considerations are discussed in more detail below (Figure 19).

Socioeconomic

Clean hydrogen can add $25–35B in gross value additions (GVA) across the U.S. economy in 2030.[109,110] Hydrogen distribution, storage and end-uses are expected to represent >70% of that GVA beyond 2030.

Based on industry estimates, the hydrogen economy can create ~100,000 net new direct and indirect jobs related to the build-out of new capital projects and new clean hydrogen infrastructure in 2030 (~450,000 cumulative job-years through 2030, Figure 19). Direct jobs include employment in fields such as engineering and construction. Indirect jobs include roles in the industrial-scale manufacturing and raw materials supply chain. An additional ~120,000 direct and indirect jobs related to the operations and maintenance of hydrogen assets could also be created in 2030 – these would not all be net new due to the broader transition to a net zero economy, for example, current gas station operators transitioning into hydrogen refueling station operators (not shown).[111,112] To attract and retain a skilled workforce, these jobs must be high paying with strong labor protections, training/placement opportunities such as registered apprenticeships, and pathways for long-term career growth. Project Labor Agreements (PLAs) are useful tools for attracting and training a skilled workforce for the infrastructure build out, and other collective bargaining agreements will support operations and maintenance workforce needs. The Pathways to Commercial Liftoff: Introduction provides an in-depth discussion of the significance of these quality jobs characteristics and how they can be achieved.

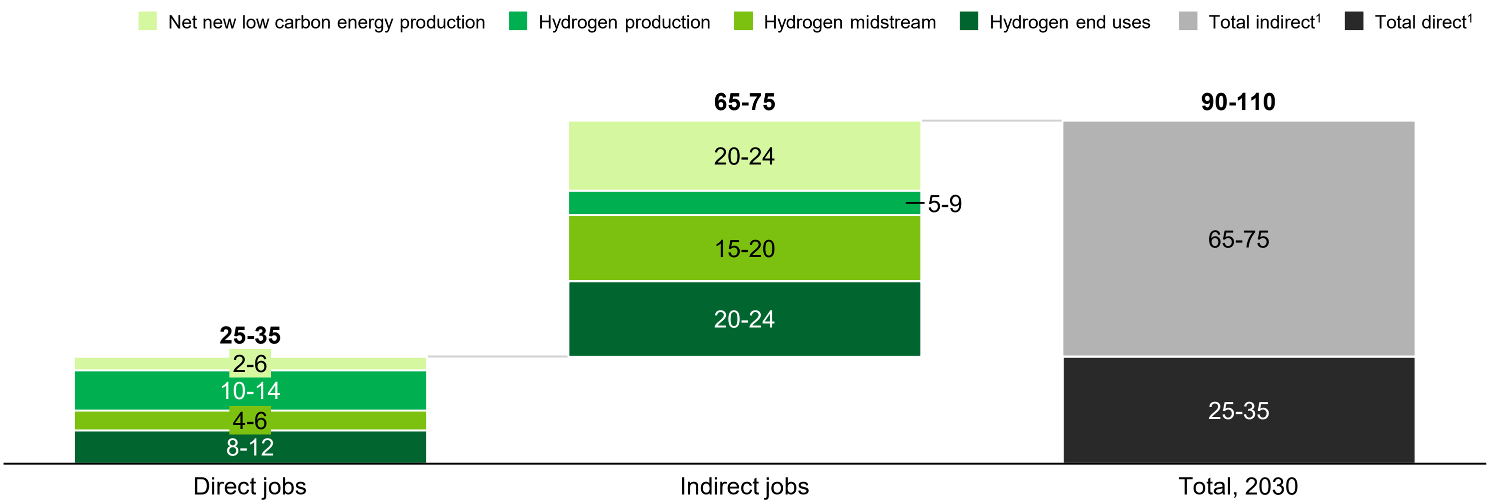
As is common in the growth of innovative sectors, jobs will not map 1:1 from incumbent industries, particularly given geographic shifts. Efforts to retain and retrain workers can minimize worker displacement. In many cases, skill sets from fossil-dependent industries like oil and gas are expected to have significant overlap with the hydrogen economy, meaning worker displacement may be lower than in other parts of the energy transition. Similarly, the hazards faced by workers are similar to those seen in the oil and gas industries. Hydrogen presents risks for workers because it is transported and stored as a compressed gas. Hydrogen leaks can cause asphyxiation if they occur in confined spaces. Hydrogen gas is also flammable, so leaks also present risks of explosions at worksites. Engaging labor unions and their apprenticeship training programs is critical through the growth of the hydrogen economy to ensure that workplaces are safe and healthy for workers and surrounding communities.

109 An economic productivity metric measuring the value that producers have added to the goods and services they have bought, measured as the difference between gross output and net output
110 See Modeling Appendix for description of methodology for calculating required investments
111 One job-year is the equivalent of one full-time job for one-year. Because construction work is temporary, infrastructure jobs are often reported as job-years.
112 Including drivers for hydrogen distribution/delivery trucks in the near term, which would be less required as pipeline infrastructure is built out beyond 2030. Analysis provided by Vivid Economics.

Achieving commercial lift-off for the clean hydrogen economy will require workforce training to smooth transitions to new jobs and industry sectors. The oil and gas sector, for example, employs ~705,000 Americans today, a workforce with experience in safely handling and transporting gases over long distances; clean hydrogen is an opportunity to securely transition these roles to an energy system aligned with climate goals.[113] If jobs are high paying and offer the free and fair choice to join a union, strong labor standards, and training/placement opportunities such as registered apprenticeships, they will attract the skilled workers required and draw new workers to the field and to the locations where they are needed.

Hydrogen market expansion will lead to new enterprise creation, including opportunities to support enterprise creation in minority-, women-, Veteran-owned or other disadvantaged businesses, and Minority Serving institutions. Constructing and maintaining these industrial clusters can have a much larger impact than a single plant. In communities where fossil tax revenues might decline, developing a clean hydrogen economy can replace lost revenue and protect jobs.

New hydrogen asset install, OEM & capex-driven jobs, by value chain step in 2030, thousands



1 Direct jobs include roles related to installing new assets while indirect jobs are roles that support asset installations (e.g., OEM and other supply chain jobs)
Source: Vivid Economics

Figure 19: Hydrogen investments could support ~100k net new direct and indirect jobs in 2030.

Energy and environmental justice (EEJ)

As with other clean energy technologies, how hydrogen is deployed can combat or exacerbate existing inequalities in the distribution of benefits and burdens within the energy system Pathways to Commercial Liftoff: Introduction. This section highlights hydrogen specific EEJ considerations.

Ensuring hydrogen projects support energy and environmental justice (EEJ) is critical not only as a moral imperative, but because project success depends on it. Hydrogen projects have already experienced delays and even cancelations when community concerns were not addressed.[114] Project partners can mitigate risks (to the project and caused by the project) by being aware of potential EEJ impacts, taking proactive steps to maximize benefits and minimize harms, and engaging in early, frequent, two-way dialogue with impacted groups. This is particularly important as hydrogen infrastructure is frequently near existing oil, gas, and chemical facilities. These facilities are disproportionately located in communities of color and low-income communities that are already overburdened and underserved.[115]

113 U. S. Energy & employment jobs report (USEER). (n.d.). Energy.Gov; U.S. Department of Energy. Retrieved February 12, 2023, from https://www.energy.gov/policy/us-energy-employment-jobs-report-useer
114 NW Natural Withdraws Application for Controversial Hydrogen Blending Experiment Following Community Uproar. (n.d.). https://www.sierraclub.org/press-releases/2022/11/nw-natural-withdraws-application-controversial-hydrogen-blending-experiment
115 Bottorff, C. (2022, January 4). Hydrogen: Future of Clean Energy or a False Solution? Sierra Club. https://www.sierraclub.org/articles/2022/01/hydrogen-future-clean-energy-or-false-solution

Because of the multiple pathways to produce, distribute, and use hydrogen, the type and magnitude of benefits and harms – and who experiences them – varies significantly by project. [116] For example, one hydrogen project might decrease local air pollution compared to the pre-project baseline, while another could increase it. Therefore, it is imperative that impacts are assessed on a project-by-project basis. The benefits and harms below reflect concerns and hopes raised by EEJ advocates, communities, and Tribes both publicly and in DOE listening sessions and requests for information.[117,118]

Safety of H2 infrastructure and CO2 infrastructure (for H2 produced with CCS)

Production: The hydrogen value chain is regulated by various federal entities, from production and storage to distribution and end-use.[119] As clean production pathways scale, communities have voiced concerns around different approaches. Reformation-based approaches with CCS can introduce concerns related to CO^2 transport and storage. These include – groundwater contamination, pipeline leakages or explosions (and resulting health impacts), induced seismicity, continued fossil fuel dependence, methane emissions, and high cost.[120,121] Compliance with existing codes/standards and best practices for deployment of clean hydrogen technologies can manage the risks highlighted above.

Midstream infrastructure: Like all pipelines (natural gas, ammonia, etc.), hydrogen pipelines are designed around codes and standards to ensure safety and account for unique properties of the molecule (e.g., embrittlement risks).[122] However, pipelines pose risks if not properly monitored and maintained, and when adequate safety measures are not in place.[123] At present, 1,600 miles of hydrogen pipeline are operational in the U.S.

Hydrogen will pose unique requirements on pipeline operators due to properties of the molecule which can make it particularly challenging to manage. Hydrogen is colorless, odorless, and highly flammable, |which can make it susceptible to combust even in small concentrations. Cautious and deliberate steps are required to install sufficient leakage detection systems that will flag hydrogen losses, even in minute concentrations. Dedicated hydrogen pipelines face a different set of challenges than pipelines in which hydrogen is blended with natural gas. New, dedicated hydrogen pipelines will take time to break ground, in part due to the nascency of the hydrogen economy combined with long construction and permitting timelines. The intervening period can be used to evaluate construction, monitoring, and maintenance plans to ensure safe construction and pipeline operation.[124,xxv]

116 The type and magnitude of benefits and harms will vary depending on pre-project baselines and implementation specifics.
117 Baldwin, S. (n.d.). Environmental Justice Impacts Of The Hydrogen Economy. Podcast. https://energycentral.com/o/energy-innovation-policy-and-technology-llc/environmental-justice-impacts-hydrogen-economy
118 Community, conservation groups unified in opposition to fossil gas hydrogen bills. (2022, February 7). Western Environmental Law Center. https://westernlaw.org/community-conservation-groups-unified-opposition-fossil-gas-hydrogen-bills/
119 Sandia National Laboratories, "Federal Oversight of Hydrogen Systems," 2021.
120 CO2 Pipelines and Carbon Capture: The Satartia Mississippi Accident Investigation. (2021, August 30). Climate Investigations Center. https://climateinvestigations.org/co2-pipelines-and-carbon-capture-the-satartia-mississippi-accident-investigation/
121 Re: Request for Comments Council for Environmental Quality's "Carbon Capture, Utilization, and Sequestration Guidance," 87 Federal Register 8808 (Docket CEQ–2022–0001). (n.d.). Climate Justice Alliance.
122 Steel makes up more than a quarter-million miles of the U.S. natural gas transmission system, but at high temperatures or high pressure, hydrogen embrittlement (permeation of H2 into steel) can crack steel pipes, leading to leakage or combustion. As noted in Chapter 2, separating and purifying hydrogen from natural gas is difficult and in general does not present break-even economics for residential and commercial applications. When blending >5% hydrogen, every appliance connected to the pipeline would have to be qualified or converted to the hydrogen blend, an extremely challenging effort. || Note that the European Hydrogen Backbone is pursuing hydrogen pipeline distribution largely through retrofits of existing natural gas infrastructure (see European Hydrogen Backbone, "A European Hydrogen Infrastructure Vision Covering 28 Countries", (April 2022, Page 3))
123 The Pacific Northwest National Laboratory contains a public database of safety codes, standards, and lessons learned to support implementation of the practices and procedures that will ensure the safe handling of use of hydrogen in a variety of applications - see Pacific Northwest National Laboratory, "Hydrogen Tools," H2Tools.org
124 Through 2030, new hydrogen pipeline use will likely remain limited, as (1) ammonia and oil-refining largely use hydrogen onsite or receive deliveries through an existing, operational vendor and (2) pipeline permitting and construction is a multi-year process; new pipelines are unlikely to be operational until at least the late 2020s.

At present, there is no industry consensus about the blending limit for hydrogen in natural gas pipelines. The California Public Utility Commission indicates that blending hydrogen more than ~5% could require the qualification or retrofit of appliances that take a blended fuel and has raised questions among the medical community related to the health impacts (including NOx) when burning hydrogen/methane blends.[125] In contrast, states like Hawaii already blend hydrogen up to ~15% in their grid.[126] The DOE HyBlend initiative aims to address the challenges associated with blending hydrogen in natural gas pipelines including risks and costs associated with different blend concentrations, materials in use, and age of the system.

Health impacts

Production: In the absence of emission control devices, SMR can result in carbon dioxide, and volatile organic compounds (VOCs) emissions, which can cause or increase respiratory illness, asthma rates, and other comorbidities.[127] However, emissions control measures for these pollutants are commercial and common. Production and delivery of natural gas for use in SMR can also release methane to the atmosphere, and fugitive upstream emissions can have associated toxic byproducts. Anticipated regulations and advances in methane monitoring are expected to reduce these emissions and provide greater measurement certainty, however. Both developments will help address methane and other pollutants from production and delivery of natural gas. Currently, even with >90% CO2 capture from CCS, SMR still results in CO2 emissions and upstream fugitive methane emissions (these upstream methane emissions also release some NOx). Low NOx burners can combat the presence of NOx in the furnace when combusting hydrogen. Similar to other emissions control devices, low-NOx burners are both commercial and commonplace.

Conversely, when electrolysis via clean power replaces carbon-intensive hydrogen, it can eliminate criteria air pollutants (e.g., SO2, particulates, and NOx), which are linked to higher risks of lung cancer and respiratory illness.[128] New electrolysis projects are expected to dominate relative to new reformation with CCS projects during the PTC period (see Figure 14).

End-use: Like most combustion processes, hydrogen combustion emits NOx– a compound that can impair lung growth in children, harm cardiovascular function, and lead to higher rates of ER visits as well as premature death.[xii] Reducing NOx emissions requires advances in pollution control technology and/or lower flame temperatures. Lower flame temperatures require either lower volumes of hydrogen (and more fossil fuels) in the combustion or de-rating the engine, causing efficiency losses and power decreases.[xxxii]

In a different example, hydrogen fuel cells, the only byproducts are electricity, water, and heat. Therefore, fuel cells eliminate air pollutants relative to fossil-based processes (e.g., internal combustion engines, natural gas peaker plants without CCS).

125 See California Public Utilities Commission, "CPUC Issues Independent Study on Injecting Hydrogen Into Natural Gas Systems", 2022, and American Medical Association House of Delegates, "Resolution 438", https://www.ama-assn.org/system/files/a22-438.pdf
126 Decarbonization: Hawaii gas. (n.d.). Retrieved January 3, 2023, from https://www.hawaiigas.com/clean-energy/decarbonization
127 Sun, Pingping, Young, Ben, Elgowainy, Amgad, Lu, Zifeng, Wang, Michael, Morelli, Ben, & Hawkins, Troy Robert. Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities. United States. https://doi.org/10.1021/acs.est.8b06197
128 Fan, Z., Ochu, E., Braverman, S., Lou, Y., Smith, G., Bhardwaj, A., . . . Friedmann, D. (2021). Green Hydrogen in a Circular Carbon Economy: Opportunities and Limits (Rep.). New York, NY: Center on Global Energy Policy - Columbia University.

Other concerns DOE has received from external stakeholders relating to the hydrogen economy include:

- Current hydrogen pipelines most often transport industrial hydrogen that needs to be filtered for high purity applications (e.g., use in fuel cell vehicles). The standard filtering process of pressure swing absorption can result in up to ~15% losses.[129] For high purity end-use applications, industrial purity hydrogen pipelines with end-use filtration losses could contribute significantly to hydrogen system leak rate. For these use cases high purity hydrogen pipelines should be considered to prevent filtration losses and thus mitigate leakage.
- If electrolysis does not dominate production mix, reformation-based pathways that emit significant CO2 and methane and/or could entrench the use of fossil fuels and fossil fuel infrastructure.[130]
- Increased costs to individual consumers (e.g., will hydrogen improve the business case of clean power assets in a way that spurs more near-term development of low-cost power, or will it increase demand for clean electricity in a way that leads to higher electricity prices?).
- Continued operation of polluting facilities including in communities looking to phase-out fossil fuel infrastructure (e.g., using hydrogen to decarbonize a facility, which could allow it to continue to operate and extend its useful life, while potentially emitting criteria air pollutants).
- Continued revenue streams/financial support provided to fossil fuel companies.
- Use of hydrogen in situations where electrification is feasible and preferred by the community (e.g., residents who are concerned about hydrogen blending for heating).

Section 3.d: Hydrogen and hydrogen-derivative exports

Key takeaways

- The U.S. has a natural advantage for clean hydrogen production due to low-cost natural resources and could emerge as a net exporter of hydrogen and hydrogen derivatives if it can move quickly to capitalize on its domestic advantages as global production centers scale-up (Figures 21, 22). These export markets could accelerate hydrogen's pathway to commercial scale and may have high willingness to pay (e.g., in countries with a strict carbon tax).
- Liftoff report updates will reflect best available information and regulatory clarity at time of publishing, which may include updates related to domestic or international regulations that have implications on hydrogen and hydrogen-derivatives for export (e.g., country-specific methods for lifecycle emissions analysis and matching requirements between electricity intake and generation sources for electrolyzers).

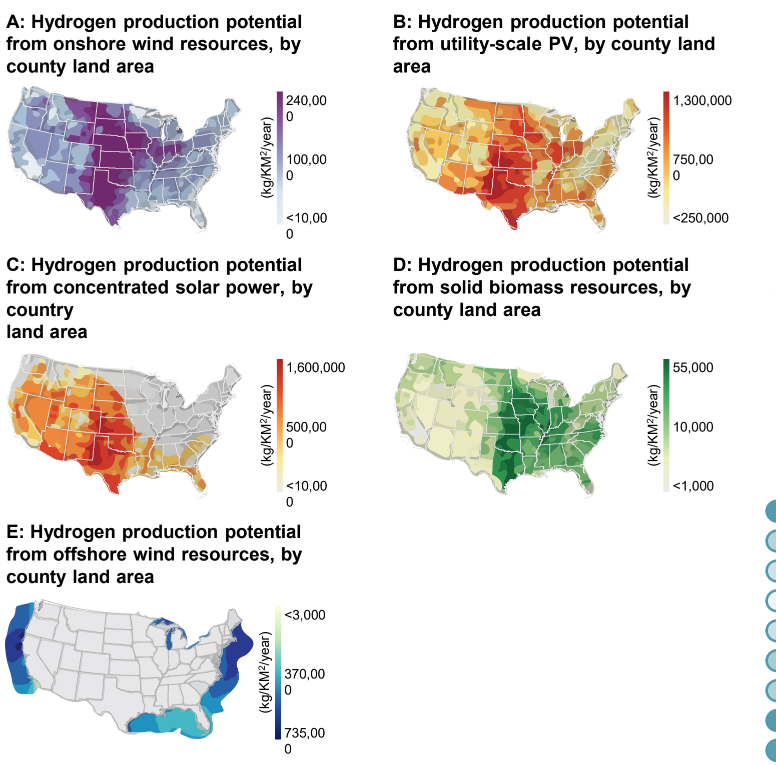
The regulatory landscape for clean hydrogen is evolving domestically and abroad. Therefore, this iteration of the Clean Hydrogen Liftoff report highlights third-party, pre-PTC scenarios, primarily conducted by the Hydrogen Council in the "Global Hydrogen Flows" report published in 2022, to **highlight some considerations** related to hydrogen as an export commodity. Further report updates will reflect best available information and regulatory clarity at time of publishing, using independent DOE modeling/analysis where available and appropriate.

129 Du, Z., Liu, C., Zhai, J., Guo, X., Xiong, Y., Su, W., & He, G. (2021). A review of hydrogen purification technologies for fuel cell vehicles. Catalysts, 11(3), 393. https://doi.org/10.3390/catal11030393
130 "Green" Hydrogen Motion Introduced at LA City Council Despite Environmental and Justice Concerns. (2022, March 4). Food & Water Watch.

Today, an international market for clean hydrogen is developing, with several international Memorandums of Understanding (MOUs) for import/export already announced. Production cost differences are expected to be large enough to support economic cross-border trade, despite the additional conversion and transport cost.[131] As a result, up to one-third of clean hydrogen and clean hydrogen derivatives in an at-scale global hydrogen economy (2050) could be traded across borders.[liv]

The U.S. has a natural advantage for clean hydrogen production due to low-cost natural resources: renewables capacity for electrolysis, low-cost natural gas, and available sequestration formations for reformation with carbon capture (Figures 20, 21). These production advantages are further improved by the IRA. However, the U.S. also faces higher labor costs and more challenging project siting/permitting requirements than many other hydrogen-producing geographies. The net result is that without the PTC, the U.S. has low production costs, but not the lowest globally (See Modeling Appendix for figures illustrating pre-PTC domestic competitiveness).

Production potential for clean hydrogen from on-shore wind, utility-scale PV solar, offshore wind, concentrated solar power, and biomass resources



Industrial clusters in the United States create potential regions for decarbonization hubs

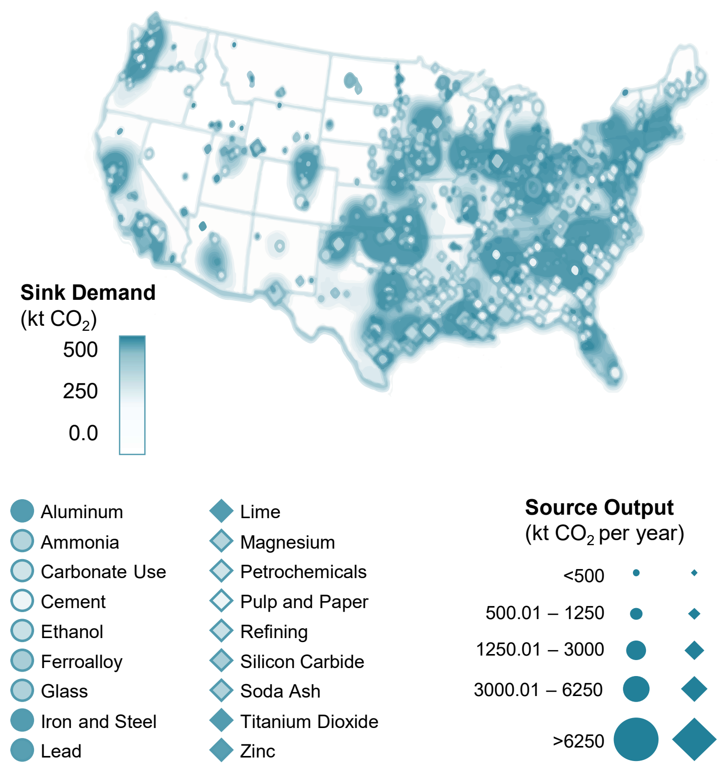
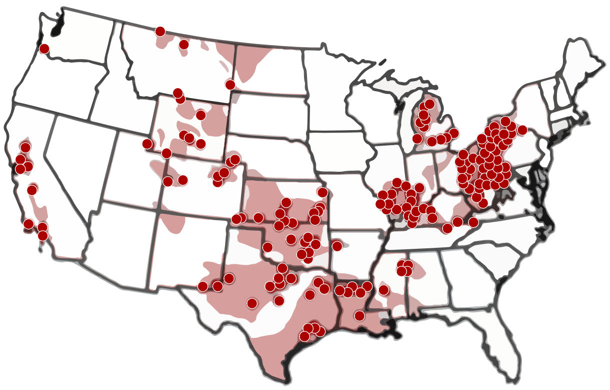


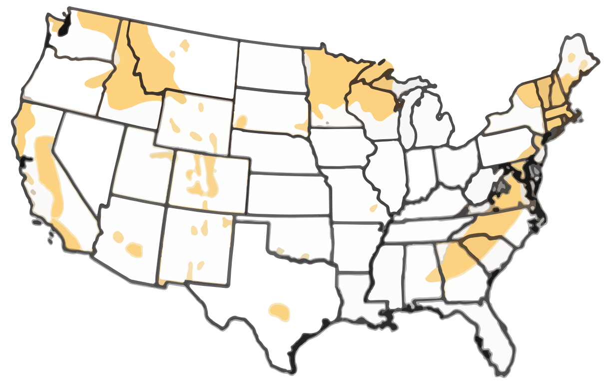
Figure 20: The United States has diverse domestic resources to produce clean hydrogen, often adjacent to existing industrial clusters. Strategic deployment of clean hydrogen will need to ensure clusters are not just a collection of disparate projects but instead are planned and scoped with one another to match scale, cost, and duration.

131 Development of global hydrogen export relies on long-distance energy carriers, such as ammonia, methanol, liquid organic hydrogen carriers (LOHCs), and liquid hydrogen. Hydrogen carriers may be imported for direct use (e.g., for ammonia or methanol) or for conversion to hydrogen.

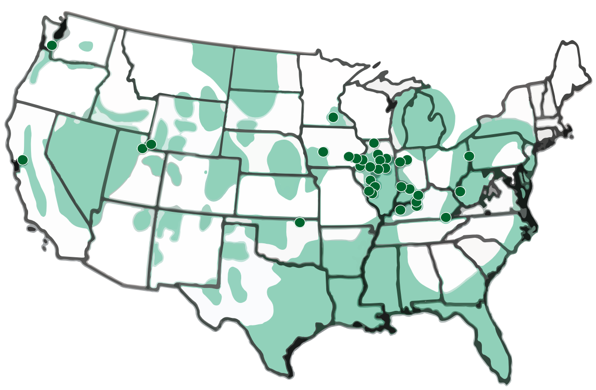
A: Oil & Gas Fields and Depleted Natural Gas Storage Facilities



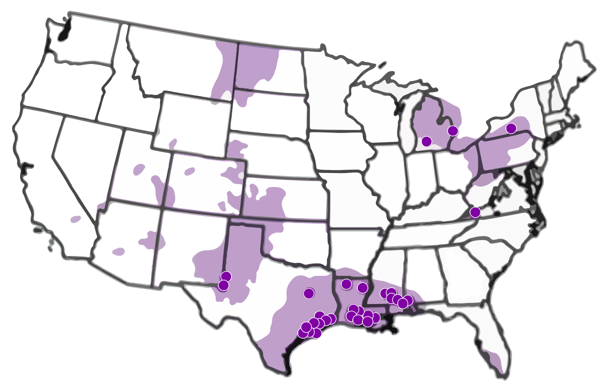
B: Hardrock Outcroppings



C: Oil & Gas Fields and Depleted Natural Gas Storage Facilities



D: Hardrock Outcroppings



Source: DOE National Clean Hydrogen Strategy and Roadmap via SHASTA - National Energy Technology Laboratory, Pacific Northwest National Laboratory, and Lawrence Livermore National Laboratory, Subsurface Hydrogen and Natural Gas Storage: State of Knowledge and Research Recommendations Report, DOE/NETL2022/3236, NETL Technical Report Series, U.S. Department of Energy, National Energy Technology Laboratory: Morgantown, WV, 2022; p. 6. https://www.netl.doe.gov/projects/files/SubsurfaceHydrogenandNaturalGasStorageStateofKnowledgeandResearchRecommendationsReport_041122.pdf.

Figure 21: The United States has an abundance of different geologies that could be used for scaled, low-cost hydrogen storage. In many cases, these regions overlap with dominant production potential regions shown in the prior figure.

The U.S. could emerge as a net exporter of hydrogen and hydrogen derivatives if it can move quickly to capitalize on its natural advantages (e.g., low-cost feedstocks, low-cost scaled storage) as global production centers scale-up. Leveraging these advantages, without IRA subsidies the Hydrogen Council forecasts that the U.S. can export ~20MMTpa of hydrogen in 2050 outside of North America, primarily in the form of hydrogen-derivatives (e.g., ammonia, methanol). The Hydrogen Council forecasts that the largest derivative market is expected to be ~10MMTpa of electrolysis-based hydrogen produced on the U.S. west coast for methanol that is exported to Asia. Synthetic kerosene and ammonia, which use clean hydrogen feedstocks, are also expected to be exported to Europe (see Modeling Appendices for pre-PTC analysis).[156]

There are also several key dynamics that could affect the size of the U.S. export market, both positively and negatively. Given the restrictions other countries (e.g., in Europe) are imposing on the emissions intensity of hydrogen they import, electrolysis may be more viable to supply export markets (with strict emissions intensity controls) than SMR with CCS Additionally, the time and distances covered in cross-border hydrogen trade present unique constraints and operating conditions on hydrogen distribution. For example, the density of hydrogen needs to be significantly increased to allow economic long-distance distribution. Two primary methods of increasing hydrogen's density are liquefaction and converting hydrogen into an ammonia carrier molecule. If used as hydrogen in the export market, liquefaction has a higher overall efficiency, however, storage times are limited due to cryogenic temperature requirements.[132]

Export markets could help accelerate hydrogen's pathway to commercial scale by:

1. Supporting a smoother and more sustained ramp in U.S. electrolyzer production capacity (e.g., ensuring electrolyzer factories maintain high uptimes and frequent orders, even after domestic demand is satisfied)
2. Accelerating the development of large-scale hydrogen pipeline infrastructure from areas of low-cost production (e.g., Midwest) to large export hubs (e.g., coasts) and thus also lower cost of delivered hydrogen to coastal demand centers
3. More quickly developing innovative contract structures and financing mechanisms by leveraging international experience of trade partners

At the same time, development of significant clean hydrogen production for export could exacerbate U.S. workforce and supply chain challenges, resulting in slowed domestic adoption.

132 If ammonia is used directly in end markets, the energy efficiency to convert hydrogen to ammonia is 33-67%, which drops to 10-40% if the ammonia is reconverted to hydrogen. In contrast, liquefaction efficiencies are typically 55-70%, although liquid hydrogen is more challenging to store due to cryogenic temperature requirements. Assumes 11-22 kWh kgH2-1 required for Haber-Bosch production of ammonia, additional ~8 kWh kgH2-1 required for reconversion of ammonia back to hydrogen, and 10-15 kWh kgLH2-1 for liquefaction Al Ghafri, Saif, et al. "Hydrogen liquefaction: a review of the fundamental physics, engineering practice and future opportunities." Energy & Environmental Science (2022).

Chapter 4: Challenges to Commercialization and Potential Solutions

Section 4.a: Overview of challenges and considerations along the value chain

Key takeaways

- Addressing the highest priority, near-term challenges in the hydrogen economy will ensure continued market acceleration consistent with the US DOE Clean Hydrogen Strategy and Roadmap. These near-term challenges are primarily related to: (1) Securing long-term offtake; (2) Lack of cost-effective midstream infrastructure; and (3) Pressure to scale the hydrogen workforce. For electrolysis, (4) the required spike in domestic electrolyzer production also presents a significant hurdle. For reformation with CCS, (5) development of regional CO2 networks and storage is a major challenge (see Figure 22).
- During industrial scaling, (6) projects will need to limit credit risk to unlock debt financing. For electrolysis, (7) scale and competition for renewable power and (8) global raw materials abundance for electrolyzers presents a challenge. In addition, (9) nascent end uses will face technology and market-specific conversion challenges.
- Long-term, hydrogen will need to overcome challenges related to (10a) equipment costs; (10b) prevailing feedstock prices; and (10c) investor uncertainty related to long-term regulatory impact on steady-state business models.
- Pre vs. Post-PTC (expiration) construction timelines impact project economics. Electrolysis projects that claimed the PTC could be more likely to operate at full utilization after the PTC sunset due to fully depreciated capital assets compared to projects built post-PTC expiration (Figure 23). Unless costs decline more rapidly than expected, electrolyzers could run at lower utilization post-PTC expiration for some end-uses, while existing reformation projects will be less affected and new projects may be constrained to certain sectors (Figure 24).

Overcoming the challenges listed below would help accelerate clean hydrogen commercial lift-off in the U.S.

Challenges to clean hydrogen commercialization

● Highest priority challenges ● Challenges to specific parts of the value chain

Area impacted	Near-term expansion ~2023-2026	Industrial scaling ~2027-2034	Long-term growth ~2035+
Entire clean hydrogen economy	1 Hesitancy to commit to long-term, scaled offtake 2 Lack of cost-effective midstream infrastructure (e.g., local & large-scale/long-distance transportation & storage) 3 Limited availability of specialized hydrogen workforce	6 Several sources of credit risk constraining debt financing needed to scale (counterparty, term vs asset life, capabilities, underwriting restrictions)	10 Long-term cost competitiveness of a) H2 equipment (e.g., electrolyzers, liquefiers) b) Feedstock (e.g., electricity or natural gas) c) financial capital (e.g., due to regulatory and business model uncertainty)
Electrolysis	4 Capacity spike required for U.S. electrolyzer production	7 Scale of and competition for renewable power 8 Global raw materials abundance for electrolyzers	
Reformation + CCS	5 Development of regional CO2 transport & storage		
End uses		9 Conversion challenges for specific end uses	

Figure 22: Clean hydrogen commercialization will occur over 3 horizons, each with its own challenges to address—the highest priority near-term challenges are related to secure offtake agreements, midstream infrastructure, and workforce availability

Challenges to address as the near-term market expands (2023–2026):

(1) Hesitancy to commit to long-term, scaled offtake: At present, producers struggle to find credit-worthy offtakers with sufficient hydrogen demand sited within an affordable distance to hydrogen production who are willing to sign long-term contracts. Many offtakers with near-term break-even points are refineries and ammonia production facilities that can retrofit their existing facilities with carbon capture and sequestration rather than seek out a new clean hydrogen producer.

Stakeholders on the production, demand, and financing sides highlight hesitancy to commit resources due to:

- **Limited price discovery or price certainty:** Near term, price discovery is limited. There is no commodity exchange or "spot price" for hydrogen, like natural gas prices at the Henry Hub. Manufacturers, developers, asset owners, and capital providers cannot hedge price volatility risk and need to account for this risk as they assess the financial attractiveness of hydrogen investments. Offtakers are also reluctant to sign long-term agreements in the early years of hydrogen scale-up if they believe prices will fall as the industry progresses along the cost curve.
- **Unavailability and reliability of supply:** Some offtakers worry that, until hydrogen production scales nationally, hydrogen supplies will be insufficient and/or too variable to meet high uptime use cases. For example, if stock-outs such as those that have been experienced at refueling stations in California were to become widespread, the industry would face additional headwinds to wider adoption.
- **Near-term policy implementation uncertainty:** Implementation details for the hydrogen PTC are forthcoming from IRS and Treasury. Until there is additional clarity, there will be uncertainty about which projects will qualify and what prices producers will have to charge to break-even. The inability to project future revenues can be a hurdle to securing financing for low carbon intensity hydrogen production projects while 45V implementation policy remains under development.
- **Long-term political uncertainty:** The hydrogen PTC provides a strong 10-year incentive. However, uncertainty about federal support for clean hydrogen after the PTC expiration leads to hesitation from producers deciding where to site long-term production and from offtakers choosing suppliers. Outside the U.S., other governments could implement incentives that allow foreign producers to export to the U.S. at a lower cost than domestic producers, lowering future prices.

The absence of standard contract structures also delays project financing. At present, hydrogen producer/buyer contracts are bespoke negotiations with volumes and willingness to pay unique to each site and use case. This variability limits replicability for project developers, offtakers, and financiers, slowing the pace at which new projects with secure, long-term offtake are established.

(2) Limited cost-effective midstream infrastructure: The absence of affordable midstream infrastructure risks slowing the hydrogen economy. Distribution and storage can more than double the delivered cost of hydrogen.[133] Near-term use cases where hydrogen supply and demand are not co-located will be significantly affected by the high cost of hydrogen distribution, with the exception of regions with existing, scaled hydrogen pipeline networks. This constraint is especially true for established industries like steel, where major production hubs are in some cases not closest to the lowest-cost hydrogen production regions.

133 Exact conditioning, storage, and transport costs are highly dependent on the volume, transport distance, storage time, and methods used. Stakeholders reported current costs of up to $10/kg

Storage costs could also add costs for many electrolytic projects compared to reformation-based projects, particularly those serving industrial offtakers who need an uninterrupted supply of hydrogen—down-cycling industrial plants reduces capital efficiency and often results in significant maintenance. Building sufficient hydrogen storage infrastructure to protect against supplier variability can quickly increase project costs.

Beyond pure cost considerations, the safety and interoperability of hydrogen infrastructure (e.g., connector and storage types at hydrogen offtake) must also be addressed to mitigate safety risks, vendor lock-in, and limited workforce mobility (across companies or regions). Safety and interoperability will be especially critical as a wide variety of new operators enter the value chain.

(3) Limited availability of specialized hydrogen workforce: Vivid Economics estimates that the U.S. hydrogen economy would need more than ~200,000 workers across direct and indirect jobs in 2030 (Section 3c).[134] Roles are primarily expected in hydrogen equipment manufacturing and field operations like construction and maintenance. Sub-sectors within the oil & gas, cryogenics, and trucking sectors have extensive experience with reformation-based hydrogen production as well as hydrogen conversion, distribution, and storage, respectively. However, new skills such as electrolyzer and electrolyzer component manufacturing, fuel cell expertise, and electrolysis facility engineering, procurement, and construction (EPC) expertise are needed. Additional, accelerated clean energy deployment is likely to further constrain EPC capacity.

(4) Electrolyzer manufacturing capacity: In some cases, producers today are being quoted wait times of 2–3 years when they order electrolyzers. <1 GW/year of operational production capacity must scale to ~20–25 GW/year by 2030 (see Section 3c).[135] Today's pipeline, based on publicly available industry announcements, would account for 4 GW/year of this total, with at least an additional 1 GW/year capacity announced that does not yet have a target COD.[136] A steep reduction in electrolyzer demand may follow this rapid capacity build-out and risk stranded assets unless the U.S. becomes an electrolyzer exporter (see Section 3d, Export).

(5) CO2 distribution and sequestration infrastructure: For reformation-based hydrogen with CCS, 2-20 million metric tonnes of CO2 would be captured and sequestered annually by 2030.[137] This quantity increases to 100–225 million metric tonnes annually by 2040 and 175–425 million metric tonnes by 2050.[138] Currently, ~25 million metric tonnes CO2 is captured and sequestered in the U.S. across all sectors, requiring significant further investment in CO2 infrastructure and coordination to manage environmental and safety considerations. Note that the permitting process for Class VI injection wells, used to inject carbon dioxide into deep rock formations, is currently multi-year in states that do not have primacy, though permitting times are projected to decrease[139]

134 Includes ~100,000 jobs related to development of infrastructure, and ~120,000 related to on-going hydrogen asset operation and maintenance
135 This scale up assumes that domestic demand for electrolyzers is met by U.S. domestic production. As a global market for hydrogen develops, an international market for electrolyzers may also develop. 20 – 25 GW is an upper bound assuming almost entirely electrolytic production through 2030.
136 Last updated at the end of 2022; Additional 1 GW/year facility has been announced, but does not yet have a COD (source)
137 Range is based on the Net Zero 2050 – high RE and Net Zero 2050 – low RE scenarios, 70-90% capture rates, 8-11 kg CO2e/kg H2 pre-capture carbon intensity, and 2 kg CO2e/kg H2 upstream methane emissions.
138 Based on projected increases in hydrogen demand
139 EPA. (2022, Oct). EPA Report to Congress: Class VI Permitting. Retrieved from: https://www.epa.gov/system/files/documents/2022-11/EPA%20Class%20VI%20Permitting%20Report%20to%20Congress.pdf

Challenges that may emerge during industrial scaling (~2027–2034):

(6) Credit risk constraining widespread debt-financing: As the hydrogen economy expands, rapid and substantial growth in debt financing will be needed across the value chain to lower the cost of capital and prevent an overreliance on equity. However, debt provision is constrained by several credit risk drivers including:

- Business model-related uncertainties including on the revenue side (e.g., reliability of offtake agreements, few methods for price discovery) and on the cost side (e.g., remaining uncertainty about cost/performance for first-of-a-kind/N-of-a-kind (FOAK/NOAK) projects)
- Few creditworthy counterparties due to large number of start-ups and first-time hydrogen producers entering the industry with no or low credit ratings and/or lack of adequate collateral
- Insufficient operating history (among new technology providers) for banks to gain comfort with the risk for the technology, establish clear requirements and underwriting criteria (e.g., debt coverage and leverage ratios), and develop debt structures and terms in line with the needs of the project (e.g., debt terms beyond 3–5 years require very strong long term mitigation mechanisms like guaranteed offtake)
- Scale-up risk in the near-to-medium-term including operators who must expand from small pilot facilities to full commercial demonstration. If the scale-up from the pilot/demonstration scale project is larger (e.g., 5 - 10x), lenders will shy away.
- More nascent hydrogen deal flow and lack of lender comfort when conducting diligence on clean hydrogen projects, (e.g., underwriting teams with limited reps evaluating hydrogen projects including industry-specific risks and risk mitigation mechanisms)

(7) Competition for clean electricity: Accelerating demand for clean electricity is a challenge across many clean energy technologies as new electricity demand (e.g., for electrolysis, direct air capture) develops in parallel to electrification of buildings and transport. By 2030, up to 200 GW of additional renewables would be needed to power clean hydrogen via water electrolysis,[140] although this value could be decreased if nuclear-powered electrolysis becomes more widely available. If renewables development is constrained, reformation-based hydrogen production is likely to be a more dominant production pathway, particularly in the 2040s and 2050s (see Figure 14).

(8) Raw materials constraints:

- **PEM – PGM materials:** Projected PEM electrolyzer production may require quantities of iridium greater than what is economically feasible to mine. If PEM electrolyzers account for ~25% of U.S. hydrogen production by 2030 and catalyst levels required for PEM electrolysis do not change, the U.S. could require between 15–30% of today's total global iridium production. The U.S. has no significant domestic source of iridium and must acquire it abroad (Ch 3). Securing high volumes of iridium could add cost and cash-flow challenges to the financial profile of PEM electrolyzer factories.

- **Alkaline:** Alkaline electrolyzers do not face critical material constraints; however, they may face higher costs from material constraints for major inputs such as nickel that are widely used in other expanding industries. Alkaline electrolyzers currently have much lower operating pressures than PEM electrolyzers, requiring significant more space and materials for construction as well as much more compression.

137 This build-out is significant (on average, could be 21–25GW/year added 2023–2030 for electrolysis alone). For context, the U.S. added ~15.5 GW of solar June '21 - July '22. https://www.eia.gov/todayinenergy/detail.php?id=52438 – 200 GW is an upper bound assuming >90% electrolytic hydrogen production build-out today through 2030.

(9) Scale-up challenges for specific end-uses: While not a challenge to the entire clean hydrogen market, specific end-uses face challenges to convert to clean hydrogen. For example, FCEVs will require a widespread refueling network. Seeing the buildout of this network would bolster confidence and would be a critical signal for fleet operators tasked with creating their ZEV strategy. Additional regulations may also strengthen the case for FCEVs and could accelerate their adoption, similar to policies and subsidies that helped BEVs begin to scale nationally. Nationally, there are ~50 open retail hydrogen refueling stations, which will need to expand significantly to provide 5-8 MMT H2 in 2040, all of which would be fuel-cell grade (highest purity) hydrogen. To date, fuel cell stations are largely limited to California where the California Energy Commission directly subsidized the majority of station capex and where recently, the state's Low Carbon Fuel Standard has strengthened the economic case for hydrogen as a clean fuel. For competing technologies, the geographic coverage of other networks is far broader: there are 145,000 gas stations in the US and more than 140,000 EV charging stations, including 6,000 fast chargers.[141] For heavy-duty fuel cell vehicles to be adopted, the trucks themselves must also be demonstrated and widely available at reasonable cost. For this to happen, vehicle fuel cell technology must improve, with capex coming down and durability increasing. Both categories represent an opportunity for additional R&D.

Challenges and considerations impacting long-term growth (2035+):

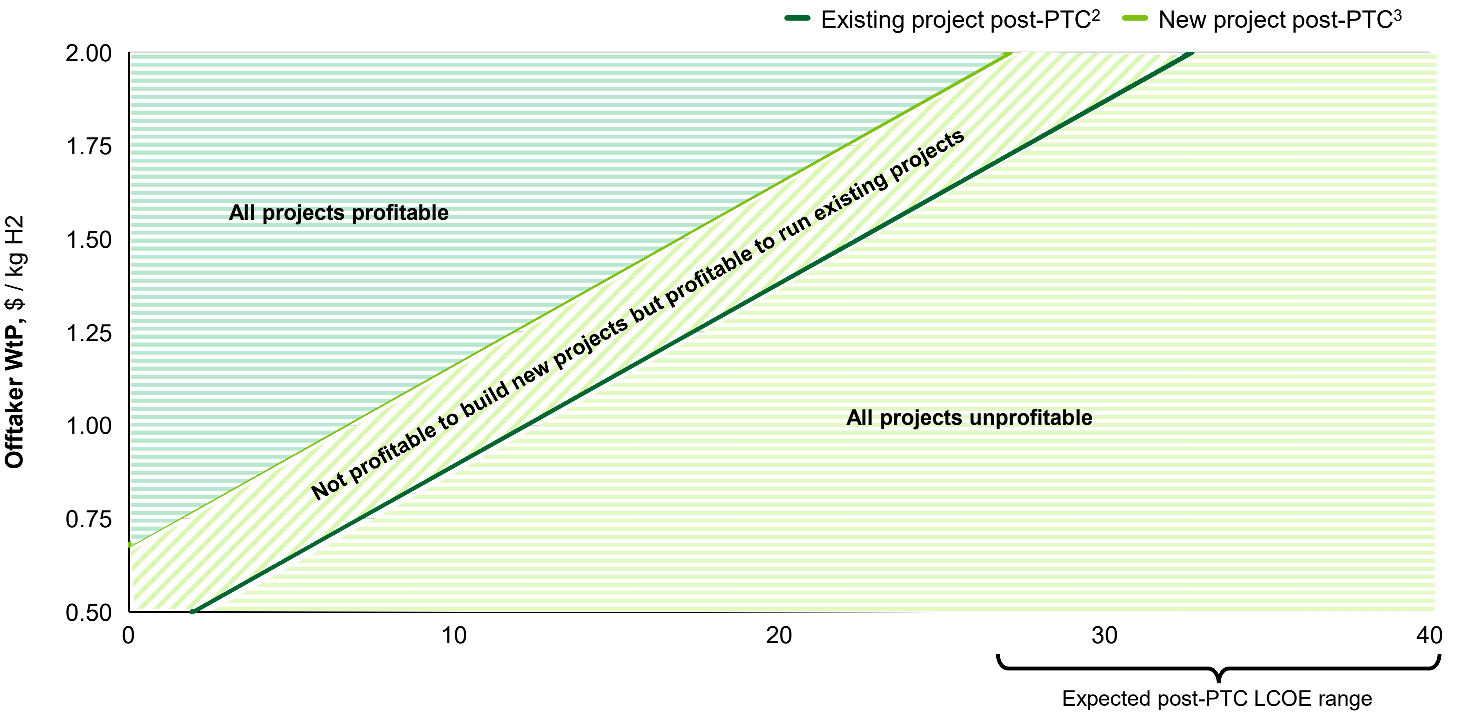
(10) Expiration of the PTC will drive margin compression, as costs to develop new projects are not currently projected to decline at a rate commensurate with the drop in revenue from PTC expiration. Therefore, project capex and opex must fall well in advance of the PTC sunset for hydrogen (projects that begin construction after 2032) to remain profitable. In 2035, electrolyzer capex is forecast to land between $375–450/kW, meaning projects would need a willingness to pay above ~$1.50/kg to be profitable at expected renewable power prices of $18–20/MWh. Some sectors will no longer be economic due to the cost of clean hydrogen relative to alternatives (e.g., electrification alternatives in high-capacity factor firm power generation).

(10a) Capex – Cost of hydrogen equipment: Upstream electrolyzer costs must decline from ~$850/kW today (uninstalled and without markup) to forecasted $200–250/kW by 2035 for alkaline electrolyzers (~70–80% decrease). Midstream liquefiers, compressors, and tank storage must also all see cost declines.

(10b) Opex – Long-term feedstock prices: By 2025, clean energy could account for ~50% of the levelized production cost of hydrogen via electrolysis. As capex costs fall, feedstock costs (electricity or natural gas) may grow to up to ~80% of the LCOH by 2050. As a result, feedstock prices will be the largest drivers of whether production projects remain economic after the PTC sunset—both existing projects that claimed the PTC and projects built after the PTC. Figure 23 shows that for electrolysis without the PTC, expected LCOEs will translate into needing a willingness to pay of at least $1.25–$1.5/kg to remain profitable. Projects selling to offtakers with lower willingness to pay may operate at lower utilization (e.g., only when low-cost electricity is available).

141 "There are more than 145,000 fueling stations across the United States. 127,588 of these stations are convenience stores selling fuel. The rest are gas-only stations, grocery stores selling fuel, marinas, etc.", American Petroleum Institute, https://www.api.org/oil-and-natural-gas/consumer-information/consumer-resources/service-station-faqs

Profitability[1] criteria for post-PTC electrolysis at full utilization



1 Defined as positive present value of post-PTC free cash flow for existing projects and an IRR >7% for new projects
2 Project built in 2023
3 Project built in 2035

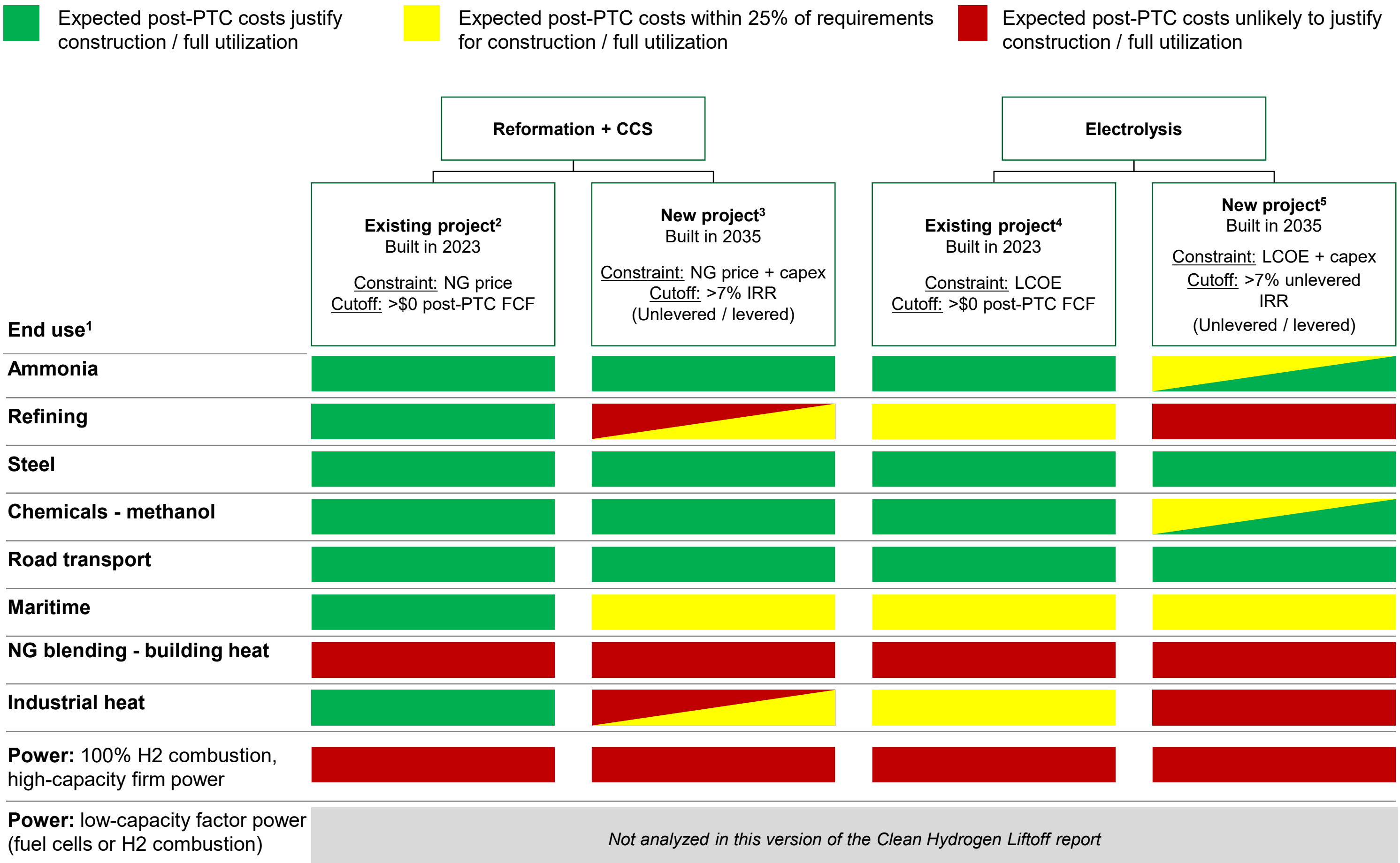
Figure 23: Electrolysis projects that claimed the PTC are more likely to operate at full utilization after the PTC sunset due to fully depreciated capital assets compared to projects built post-PTC expiration

In the long-term, economic viability of hydrogen production projects will vary by offtaker (dependent on the offtaker's willingness to pay), the hydrogen production technology, and whether the project began construction before or after the PTC sunset in 2032 (see Figure 24).[142] Most industrial use cases have sufficient willingness to pay to justify new construction after 2032 and continued operations of existing projects that no longer qualify for the PTC after 10 years in operation. Of course, this is dependent on realizing significant cost-downs for capex and renewable power. In the absence of these cost-downs, producers may need to raise prices, where feasible, to cover their operating expenses, likely immediately before and after the PTC term ends.

By 2035, both new and existing projects that no longer qualify for the PTC (after 10 years in operation) will not be economical for natural gas blending (for building heat) and power offtakers (100% H2 combustion for high-capacity firm power), motivating the need to find new offtakers, or in the case of electrolysis, run at lower utilization during times of low-cost power. Reformation-based hydrogen cannot generally be produced economically at low utilization. In this Liftoff report, IRRs were not analyzed for lower-capacity factor power applications of clean hydrogen (combustion or fuel cells).

Variations in the cost of capital by hydrogen production company and for development of projects selling hydrogen into different end-uses will also allow certain producer/offtaker combinations to remain viable at lower willingness to pay. The development of debt-based project financing for hydrogen production will also allow a greater fraction of potential new projects to clear investment hurdle rates by allowing increased levered returns.

142 Note that willingness to pay (WTP) must include delivery, storage, and dispensing cots – not just hydrogen production costs



Mixed boxes show how an 80% debt financed project can help clear the IRR cutoff for new projects in the 2030s

1 Willingness to pay: Ammonia ($1.5/kg), Refining ($1.0/kg), Steel ($2.0/kg), Methanol ($1.5/kg), Road transport ($4.5/kg), Aviation ($1-2/kg), Maritime ($1-2/kg), NG blending ($0.50/kg), Industrial heat ($1.0/kg), Power ($0.50/kg)
2 ATR facility capex (500k Nm³/h capacity): $1.05 billion; CCS capex (500k Nm³/h capacity): $600 million; Natural gas: $4.8/MMBtu; CO2 transport and storage: $50/tonne CO2
3 ATR facility capex (500k Nm³/h capacity): $960 million; CCS capex (500k Nm³/h capacity): $490 million; Natural gas: $3/MMBtu; CO2 transport and storage: $41/tonne CO2
4 Assumes ~2 MW, 450 Nm³/h alkaline electrolyzer installed capex: $1400/kW; assumes Class 1 onshore wind; post-PTC LCOE (2035-2049): $15-17/MWh; Capacity factor range (2033-2049): 54-55%
5 Assumes ~90 MW, 20,000 Nm³/h alkaline electrolyzer installed capex: $390/kW; assumes Class 1 onshore wind; LCOE range (2037-2061): $15-17/MWh; Capacity factor range (2037-2061): 54-55%
Sources: Hydrogen Council, DOE National Hydrogen Strategy and Roadmap, NREL Annual Technology Baseline

Figure 24: Unless costs decline more rapidly than expected, electrolyzers could run at lower utilization post-PTC expiration for some end-uses. Some end-use segments (i.e., clean hydrogen for lower-capacity factor power) were not analyzed in this iteration of the Liftoff report.

(10c) Capital formation – Long-term regulatory impact: Investors, project developers, and offtakers are all seeking further certainty on the long-term operating environment, including how to think about regulatory implications at the sunset of the PTC. The U.S. will face competition from other regulatory paradigms that will impact the attractiveness of U.S. investment relative to other geographies with different cost profiles (land and labor) and regulatory landscapes (incentives, siting/permitting restrictions). Long-term, sector-specific and economy-wide policies that value low carbon commodities (e.g., low carbon-intensity steel, ammonia, clean chemicals) could further strengthen the business case and long-term project certainty for many hydrogen end-uses.

Section 4.b: Priority solutions

Key takeaways

Cross-cutting solutions will address the challenges noted above. These solutions include:

1) Invest in the development of midstream infrastructure
2) Secure supply chain investments
3) Develop regulations for a scaled industry
4) Standardize processes and systems across the hydrogen economy
5) Accelerate technical innovation through R&D
6) Expand the hydrogen workforce
7) Expand and accelerate the capital base

To scale the hydrogen economy, a set of near-term actions will help address the challenges outlined above. These solutions require coordination and momentum from both private and public sector stakeholders.

1: Invest in the development of midstream distribution and storage infrastructure

Cost-effective midstream infrastructure is critical to enable distributed use cases and expand the hydrogen market beyond projects where co-location is feasible (Section 4a). In parallel, affordable CO2 pipeline transport will be needed for CCS connected to reformation-based hydrogen production which may account for up to 80% of U.S. clean hydrogen production in 2050.[143]

To accelerate midstream infrastructure, regional demand should be aggregated[144] to improve the investment case and drive down unit costs through shared utilization. Near-term, the Federal government's $8 billion investment in Regional Clean Hydrogen Hubs will catalyze regional demand pools and support cost-sharing across distribution and storage resources.

These and other actions to incentivize midstream infrastructure should be complemented by:

- Supply chain scale-up for midstream equipment components (e.g., tube trailers) (Action #2)
- Regulatory clarity around distribution and storage requirements (e.g., on-site storage compliance requirements) (Action #3)
- Development of standards to establish safety protocols and enable interconnections across different production types, midstream modes, and offtakers (Action #4), and
- Technological advancement in midstream technologies (Action #5).

2: Secure supply chain investments

Growth of the hydrogen economy will require the rapid scale-up of many technologies that do not yet have established supply chains (Ch 3, Section 4a) including electrolyzers, carbon capture equipment, hydrogen distribution equipment (liquefiers, tube trailers), and end-use specific equipment such as refueling stations.

143 In a constrained RES scenario
144 In the short to medium-term, and to the extent possible

Expanding domestic manufacturing capacity, particularly for renewables, electrolyzers, and hydrogen midstream components, will be critical. Long-term purchasing agreements between hydrogen developers and manufacturers could help smooth demand and encourage the ramp-up of manufacturing capacity to avoid bottlenecks in production chains. Additionally, stakeholders across the hydrogen industry should consider exploring consortium-based procurement entities for critical components (e.g., Partnership Intermediary Agreements).

From the public sector, direct incentives for electrolyzer supply chains, analogous to the CHIPS Act for semiconductors, could crowd-in private capital. Industrial policy interventions to maintain idle electrolyzer utilization post-2030 could also reduce the risk that rapidly scaled electrolyzer capacity could be stranded by a drop in demand after the PTC sunsets.

In addition to advanced/finished components, many supply chains will also be constrained by lack of raw materials and critical inputs (e.g., PGM catalysts in PEM electrolyzers). To secure raw materials, the U.S. could develop strategic reserves for minerals with constrained global availability. The U.S. can also bolster supply through trade agreements with producing countries and simultaneously increase investment in domestic refining capacity. In parallel, R&D can reduce the volume of constrained materials that are needed for equivalent output, and expansion of domestic recycling capacity can aid in faster mineral recovery. Public sector momentum exists in this space, with the Infrastructure Investment and Jobs Act establishing $500M in grant funding, some of which is intended for recycling related to clean hydrogen.

3: Develop regulations for a scaled industry

Industry stakeholders frequently cite regulatory uncertainty as a challenge to investment (Section 4a). For example, forthcoming guidance from IRS and Treasury on how provisions of the IRA will be applied will provide crucial information to investors, project developers, and end-users.

Additionally, local permitting and siting challenges also risk holding back capital flows. Power prices are the largest component of electrolysis' levelized cost of hydrogen (LCOH), meaning permitting challenges for renewables and nuclear energy could drive increased costs that challenge electrolysis scale-up. Other aspects of the value chain, such as renewables development and hydrogen refueling stations, may also take multiple years to permit, which could delay clean hydrogen liftoff. For reformation with CCUS, geologic storage projects face a Class VI well approval process that developers say will require predictable and consistent timelines and appropriate technical assistance. Recent legislation has provided funding to the EPA to build out the Class VI programs and process Class VI permitting applications. The Infrastructure Investment and Jobs Act (IIJA) also provides EPA with additional funds to both build regulatory capacity at the federal level and to provide grants to States, Tribes, and Territories seeking to develop Class VI primacy. Local, state, regional, and federal agencies should coordinate permitting and siting regulations, working to ensure processes are streamlined and consistent with each other where possible. Adequate staffing to handle permit requests and guidance for developers on streamlined permit processes would help to reduce wait times. Communication, education and collaboration with landowners and local communities could also help ease siting challenges, and leasing of public lands could provide land that is easier to site, in some instances (see Section 3c, Environmental Justice Considerations).

Hydrogen is covered today by chemicals standards regulations, but many of the current classifications and regulations are not designed with the full range of potential hydrogen end-use applications in mind. For example, hydrogen storage tanks are subject to National Fire Protection Association regulations, which limits on-site storage volumes.

In addition to evolving existing regulations, new regulations will also need to be developed to ensure safe, rapid project development and ongoing operations while enabling at-scale deployment of new types of infrastructure (e.g., regulations on purity of hydrogen that can be distributed through hydrogen-dedicated pipelines that serve many different offtakers).

4: Standardize processes and systems across the hydrogen economy

Along the hydrogen value chain, many companies have developed bespoke tooling and standards that could create lock-in to a particular vendor or technology solution. This variability reduces interoperability, customer choice, and labor market liquidity, and can increase the time and costs associated with project development.

At the same time, lack of thorough, consistently applied standards can lead to safety hazards. Hydrogen is flammable at a wide range of concentrations in air and can ignite more easily than gasoline or natural gas.[145] Standardized systems and processes around materials, system design, ventilation in operational areas, and leak detection can help mitigate potential risks.

Private sector standards organizations can play a critical role in driving cross-industry standard operating procedures (SOPs) and component interoperability (e.g., hydrogen transfer protocols during drop-off) as well as development of safety standards. Standardization of protocols and components across geographies (e.g., at energy transfer ports) would also help avoid delays in cross-border trade in hydrogen and its derivative products. The public sector can play a role by convening industry stakeholders to develop national standards, coordinating with international groups to ensure interoperability for global as well as domestic trade.

5: Accelerate technical innovation through R&D

Scaling the clean hydrogen market requires:

- Continued R&D to drive down cost in clean power, electrolyzers, fuel cells, and CCS;
- Commercialization of nascent electrolyzers, such as AEMWEs and SOECs;[146,147]
- Improved conversion efficiency and cost of alternative liquid-phase hydrogen carriers for midstream distribution and storage; and
- Reduced fuel cell cost and increased durability for use in road transportation

145 Department of Energy Hydrogen and Fuel Cell Technologies Office, “Safe Use of Hydrogen,” (source)
146 Anion-exchange membrane water electrolyzers
147 Solid-oxide electrolysis cells

Electrolyzers need to see 50–80% cost declines by 2030 to follow the growth pathway detailed in this report. While standardization, design to value and manufacturing scale-up will represent a significant portion of the cost-down, technological innovation is also needed. For example, PEM electrolyzers can see cost declines through the reduction in iridium and other PGM requirements via improvements in iridium catalyst performance, substitution with other catalyst compositions, and/or increased catalyst surface area. For emerging electrolyzer technologies, the biggest R&D needs include membrane technology (for AEM electrolyzers) and durability plus lower-temperature operation (solid-oxide electrolysis cells).

Continued development of new clean energy generation materials and technologies (e.g., perovskites and other low-cost, thin film solar cells) that could reach lower cost levels may also reduce the cost of hydrogen produced via electrolysis in the future.

For CCS, improvements in performance and reductions in cost for emerging carbon capture technologies such as adsorption will be most critical to reduce the cost of reformation with carbon capture.

Finally, hydrogen remains costly to distribute and store. R&D in alternative liquid-phase hydrogen carriers that are stable in ambient/near-ambient conditions (e.g., ammonia, liquid organic hydrogen carriers) could reduce the cost of midstream infrastructure which today must be at cryogenic temperatures to keep H2 in its liquid phase. R&D efforts on these carriers can focus on reducing conversion costs to and from hydrogen and mitigating lifecycle emissions and toxicity.

6: Expand the hydrogen workforce

While there is some opportunity for transferability of talent from adjacent industries (e.g., oil and gas), the engineering, operations, managerial and construction workforces for hydrogen must scale quickly. A skilled workforce is most needed for manufacturing (electrolyzers, liquefiers, compressors, and storage equipment), EPCs that install both electrolyzer facilities and midstream pipelines (Section 4a), and hydrogen distribution truck drivers.

Workforce development can be accelerated via:

- On-the-job training programs and flexible work policies to allow more time for training
- Collaborative, targeted training programs between the private sector, vocational schools, community colleges, and universities
- Skills-based (rather than credential-based) hiring practices to widen the pool of candidates and facilitate job transitions (e.g., from fossil-fuel-based sectors that are expected to decline).
- The public sector will likely have a role in supporting workforce development and training, although many of these initiatives are typically led by the private sector in collaboration with universities and vocational schools. Policy can be used to support good jobs which can then attract talent and motivate investment in skills. For example, the hydrogen PTC already accounts for some prevailing wage and apprenticeship requirements which could also be extended to the 45Q subsidy.

7: Expand and accelerate the capital base

Scaling clean hydrogen will require a ~4–10x scale-up in capital by 2030, requiring investment across the capital stack. Investors are seeking ways to expand their diligence capabilities for novel projects and technologies, appropriately price and manage risk, and leverage creative contracting and partnership structures to move quickly. Potential actions include:

- **Using public sector dollars and guarantees to de-risk projects and catalyze private sector investment:** Federal dollars can play a critical role in financing novel, first-of-a-kind projects in hydrogen technologies that require scaled deployments to come down the cost curve. Grant and cost-share programs can be used to crowd-in private sector dollars via shared infrastructure investments. These include Hydrogen Hubs which will promote shared infrastructure and economies of scale for regional hydrogen assets that no single investor or company could underwrite on a standalone basis.

- **Developing and encouraging contracting mechanisms that manage price and volume risk** in hydrogen projects. These mechanisms may involve bilateral long-term offtake agreements between producers / buyers for individual projects, which include minimum volumes over long periods of time at floor prices to ensure minimum compensation to hydrogen production projects. In the initial stages, these contractual arrangements may require public sector support or public-private partnerships to catalyze their introduction. For example, some stakeholders have suggested that the government could guarantee price or volume floors in offtake agreements. These floors could help capital providers evaluate cashflows by providing some insulation against regulatory uncertainties and pricing volatility. Consortia between industry players can also help de-risk investment and enable private capital. For example, consortia between producers, truck manufacturers, and fleet operators can de-risk transportation end-uses.

- **Developing a hydrogen commodity market to facilitate price discovery** (similar to natural gas and crude oil markets) and reduce volatility in pricing expectations in the absence of bilateral long-term contracts. Other price discovery mechanisms could include using fixed-price contracts, establishing hydrogen exchanges, using hedging contracts, and developing pricing surveys with widely available results. The goal of these efforts would be to create a sufficiently liquid market to enable regional or national pricing distribution hubs analogous to WTI Crude or Henry Hub natural gas, which would lower the cost of capital by reducing the risk for both producers and end-users. This type of open pricing would also be a key metric for measuring the liftoff of clean hydrogen. The market clearing price of hydrogen could be compared to the price required for TCO breakeven, allowing the industry to understand when new end-uses become “in the money.”

- **Establishing a track record of at-scale projects financed with debt:** Most banks need to see a few successful, at-scale project finance examples to consider the technology mature enough for their risk appetite. The government can accelerate this process by providing direct lending to projects or providing guarantees. In both cases, the ultimate objective is “crowding in” commercial banks to increase their focus on the technology and development of their hydrogen project underwriting capabilities. In addition, lenders can build specific credit “sandboxes” to explore these demonstration projects, as part of their learning process. These “sandboxes” would need to be a small fraction of a bank’s assets and would require higher reserve requirements from regulators. However, it could represent an approach for banks to more quickly enter areas they expect to grow rapidly, particularly if the government provided guarantees to partially offset the risk. Once these projects show the technology is bankable, the government can accelerate information-sharing among other hydrogen project owners and lenders.

- **Expand diligence capabilities to accelerate investor comfort with clean hydrogen.** Leverage the vast federal research network including National Labs and Federal Agencies to support investors looking to build teams and funds around emerging clean energy technologies. Build an anonymized set of public case studies that would help financiers become more familiar with the risk/return profile of FOAK projects.

Leading institutions that develop these capabilities will have the opportunity to gain share in a rapidly accelerating market. Building these capabilities would include investing time and talent to build expertise in hydrogen project underwriting and credit risk analysis. Capital providers may also explore innovative financial products and services such as green bonds, M&A advisory/financial support, and specific contract structures to mitigate risk (e.g., guarantees, insurance).

Chapter 5: Metrics and Milestones

The DOE will track two types of key performance indicators to understand the progress needed for successful market scale-up of clean hydrogen technologies:

- **Leading indicators** are early signs of the relative readiness of technologies and markets for at-scale adoption; and
- **Lagging indicators** are confirmation of successful scaling and adoption of clean hydrogen technologies (e.g., including evidence and progress toward net-zero targets).

Near-term expansion
~2023-2026

Industrial scaling
~2027-2034

Long-term growth
~2035+

Lagging indicators | Leading indicators

Announced uninstalled electrolyzer cost (low temp): on track for **$100 – 250/kW by 2030**

MMTpa contracted demand by sector

Announced H2 pipelines: **Tracking**

Announced GW/year domestic electrolyzer manufacturing capacity: **20-25 GWpa by 2030**

Operational GW/year domestic electrolyzer manufacturing capacity: **20-25 GWpa by 2030**

Operational H2 pipelines: **Tracking miles by 2030**

Contracted uninstalled electrolyzer cost (low temp): **$100 - 250/kW by 2030**

H2 produced per year: **20 MMTpa by 2040**

Operational H2 pipelines: **Tracking**

Number of refueling stations planned and permitted: **Tracking**

Figure 25: Clean hydrogen milestones reflect production capacity, cost, and investment requirements required for scale. DOE will track these milestones and those detailed in the table below to evaluate progression of the domestic clean hydrogen economy.

The DOE will track leading and lagging indicators to track progress towards net zero in an integrated way. In each phase of commercialization, there are a few critical metrics which can indicate whether clean hydrogen is on track for the path to commercial liftoff as described in this report. These milestones do not represent DOE targets but are important markers of progress to create confidence across the ecosystem.

Categories	Key Metrics		Units	Milestones 2030	2040	2050
Leading indicators						
Contracted offtake	Contracted clean hydrogen demand by sector (Ammonia, Oil refining, Steel, Methanol, HDMD Road transport, Aviation, Maritime, NG blending in residential/commercial, Industrial heat, Power)		MMtpa			
Units announced	Upstream - clean H2 production capacity (announced)		MMtpa	10	20	50
	Upstream – clean H2 production capacity (reached FID)		MMtpa	10	20	50
	Mid-stream	H2 pipelines	Miles	Tracking - Low thousands		
		Type IV tube trailers	#	Tracking - Low thousands		
Announced unit costs	Announced uninstalled electrolyzer cost (Low temperature electrolyzer, 46 – 51 kWh/kg efficiency, 80,000-hr life)		$/kW	100 – 250		
	Announced uninstalled electrolyzer cost (High temperature electrolyzer, 44 kWh/kg efficiency, 60,000-hr life)		$/kW	200 – 300		
	LCOH by 2026		$/kg	2 (by 2026)		
Technology performance	Electrolyzer efficiency - Low temperature		kWh/kg	46 - 51		
	Electrolyzer efficiency - High temperature		kWh/kg	At or below 44		
	Electrical consumption		kWh	37		
	Thermal consumption		kWh	18		
	Liquefaction efficiency		kWh/kg	7 by mid-to-late 2020s		
	Compression efficiency		Total efficiency	Tracking		
	Refueling stations		# kg/day capacity	Tracking		
Clean energy availability	Clean energy deployed for hydrogen production		Gigawatts (GW) Dependent on share of electrolytic vs reformation-based H2	Up to 200		
			$/MWh LCOE	22 Over 44% capacity factor (across time horizons)	19	17
Announced supply chain capacity	Announced domestic electrolyzer manufacturing capacity		Gigawatts per year (GW/year)	Tracking		

Categories	Key Metrics	Units	Milestones 2030	2040	2050
Lagging indicators					
Operational deployment	Clean hydrogen produced per year	MMTpa	10	20	50
	Refueling stations (Number, reliability)	#	Tracking		
		Uptime vs plan	Tracking		
	Operational H_2 pipelines	Miles (of new-build H2 pipelines demonstrated)	Tracking, to be updated after H2 Hub awards		
	Operational H_2 tube trailers	#	Tracking - Low thousands		
	Contracted electrolyzer cost - Low temperature	$/kW	100 – 250		
Investment deployed	Levelized cost of clean hydrogen (LCOH)	Produced US $ per kilogram	$1 / kg for best-in-class projects in specific locations in early 2030s		
	Investment in clean hydrogen supply – by end use sector	$B	Tracking		
	Contracted uninstalled electrolyzer cost (Low temperature electrolyzer, 46 – 51 kWh/kg efficiency, 80,000-hr life)	$/kW	100 – 250		
	Contracted uninstalled electrolyzer cost (High temperature electrolyzer, 44 kWh/kg efficiency, 60,000-hr life)	$/kW	200 – 300		
	Delivered to fueling stations	US $ per kilogram	Tracking, to be updated after H2 Hub awards		
Operational supply chain capacity	Domestic electrolyzer output	GW per year	20-25 (upper bound – see Modeling Appendix)		
Emissions	CO2 reductions enabled by clean H2 economy	Tonnes of CO2e avoided	Tracking	--	10% by 2050 (vs. 2005 emissions)
	NOx reductions enabled by clean H2 economy	MMTpa NOx	Tracking	--	
Jobs	Clean hydrogen jobs created or transitioned	Job-years	Tracking	--	
GDP	GDP impact	USD	Tracking	--	

Chapter 6: Modeling Appendix

Sources of insight: This effort draws on research and analyses conducted by the Department of Energy, National Labs, and databases/modeling approaches developed through collaboration with industry participants. Hydrogen industry forums, publications from research institutions, public announcements, and structured interviews with more than 40 organizations across the hydrogen value chain also informed this body of work.

Contextualizing this work:

- **This report should be considered a working document and will be refreshed on a regular basis** to incorporate the latest developments in clean hydrogen technologies and business models, as well as additional input from industry stakeholders.
- **Readers should expect updates to models and input parameters,** in particular because of the accelerating pace of change and innovation in the domestic hydrogen market.
- **Modeled scenarios represent illustrative case studies and should not be read as comprehensive** of all technology input parameters, commercial operating conditions, or exogenous market considerations.
- **Questions and feedback on this report should be directed to liftoff@hq.doe.gov to help inform follow-up research and refreshes of this document**. Input and feedback should not include business sensitive information, trade secrets, proprietary, or otherwise confidential information. Please note that input and feedback provided is subject to the Freedom of Information Act.

The below appendix should be used for readers to understand the scope and limitations of scenarios presented in the report.

Methodology 1: Role of hydrogen in decarbonizing global CO2 emissions

The data shown in Figure 1 was published in the McKinsey Global Energy Perspective 2021 based on global emissions data from the IEA World Energy Outlook 2021. The segmentation of end uses by “strong,” “some,” and “limited” potential was made through expert input from the DOE Hydrogen and Fuel Cells Technology Office.

Sectors labeled “strong potential” are sectors where hydrogen is one of few decarbonization options and is likely to be adopted on a large scale if decarbonization is pursued. Sectors labeled “some potential” are sectors where hydrogen is one of several decarbonization options and clean hydrogen may face more challenges to adoption when competing on specific dimensions with alternative technologies (e.g., resource maturity, market acceptance – see DOE Adoption Readiness Levels for specific commercialization challenges. Sectors labeled “low potential” are sectors where hydrogen either cannot play a role in decarbonization or where the economics of hydrogen use are not favorable.

Key inputs and assumptions:

See methodology section.

Objective of analysis:

Illustrate hydrogen’s myriad uses and potential to decarbonize based on a global emissions data set.

Considerations & limitations of approach:

These percentages represent the percentage of total emissions represented by end use sectors, not the potential emissions reduction due to hydrogen in that sector. For example, cement also has emissions due to conversion reactions during processing and that cannot be mitigated with hydrogen. The low end of the "strong potential" range represents hydrogen playing a role only in chemicals, long-haul trucks, and refining decarbonization. The high end of the range also includes iron and steel, maritime, and aviation.

Methodology 2: Carbon intensity by production pathway

Carbon intensity data is from the Hydrogen Council report “Hydrogen decarbonization pathways: A life-cycle assessment” and refined with expert opinion from Dr. Amgad Elgowainy (Argonne National Laboratory). The methodology for the Hydrogen Council report is described below.

This report is an assessment that uses a lifecycle analysis (LCA) approach for greenhouse gas (GHG) emissions. The analysis includes GHG emissions related to energy supply and use. Fugitive gas emissions, such as methane leakage across gas production and supply, or hydrogen losses from flushing procedures, have been considered in the assessments assuming best available technology and operational practices for a given regional energy source or route. Production conditions can vary significantly from producer to producer and region to region - global assumptions have been applied for a generalized LCA assessment. For life-cycle modeling and calculations, the LBST software E3database was used in accordance with standard practices regularly applied to life-cycle assessments for clients such as the Joint Research Centre of the European Commission, EUCAR, Concawe, and other industry as well as environmental interest groups.

Key inputs and assumptions:

For grid-based carbon intensities, the range of grid carbon intensities by state were used from the Scott Institute for Energy Innovation at Carnegie Mellon University. The lower bound represents a part of the grid and time of the day that is powered exclusively by renewables or nuclear. All other input assumptions were imbedded in the Hydrogen Council report.

Objectives of analysis:

Highlight the differences in carbon intensity between different production pathways as well as the project-to-project variability within a pathway.

Considerations and limitations of approach:

Methane leakage is inherently challenging to measure and varies from project-to-project and operator-to-operator. Since the PTC carbon intensity cutoffs include methane leakage, accurate measurement of these values will be critical.

Methodology 3: Electrolyzer and reformation capex costs

The electrolyzer capex costs shown in Figure 3 are based on reports from the Hydrogen Council and Bloomberg New Energy Finance. The methodology the Hydrogen Council used in their report “Path to hydrogen competitiveness: a cost perspective” to collect electrolyzer capex costs is described below.[xxvi]

An independent third-party clean team collected, aggregated, and processed electrolyzer cost forecast data from participating Hydrogen Council members for 2020, 2025, 2030, 2040 and 2050, producing anonymized median and top quartile performance data. This data includes electrolyzer system, assembly, transportation, and installation capex costs. Electrolyzer technologies included were alkaline water electrolyzers (AWE), proton exchange membrane (PEM) electrolyzers, and solid oxide electrolysis cells (SOECs). Costs for three sizes, ~2 MW, ~18 MW, and ~90 MW were included. For each electrolyzer size and technology, opex costs were also included such as for operations and O&M costs as well as refurbishment (AWE) or stack replacement (PEM and SOEC). The findings were then tested with insights from an independent group of experts in government and academia, including Dr. Alan Finkel, Australia's Chief Scientist; Dr. Timur Gül, Head Energy Technology Policy Division at the International Energy Agency; Tom Heller, Chairman of the Climate Policy Initiative; Dr. Noé van Hulst, Hydrogen Envoy at the Netherlands Ministry of Economic Affairs & Climate Policy; and Lord Turner, Chair of the Energy Transitions Commission.

The electrolyzer capex cost ranges shown include both the Hydrogen Council median and top quartile data as well as the Bloomberg New Energy Finance data for alkaline and PEM configurations.[xxvii] Only Hydrogen Council data is available for SOEC capex costs. These costs are used as inputs in other analyses across the report, including the reformation and electrolysis production capacity split (Methodology 11, Figure 14), required hydrogen value chain investments (Methodology 16, Figure 16), levelized production cost calculations (Methodology 4, Figure 2, 11, 12), and cashflow modeling (Methodology 17, Figure 24).

Like the electrolysis cost information, through the Hydrogen Council's report "Path to hydrogen competitiveness: a cost perspective", an independent third-party clean team collected, aggregated, and processed steam methane reforming (SMR) and autothermal reforming (ATR) cost forecast data and the analogous carbon capture and storage forecast data.i These data are from participating Hydrogen Council members, forecasted for 2020, 2025, 2030, 2040 and 2050. For this report, the carbon capture and storage data were further refined through expert opinion and additional stakeholder engagement. These costs are used as inputs in other analyses across the report, including the reformation and electrolysis production capacity split (Methodology 11, Figure 14), required hydrogen value chain investments (Methodology 16, Figure 16), levelized production cost calculations (Methodology 4, Figure 2, 11, 12), and cashflow modeling (Methodology 17, Figure 24).

Key inputs and assumptions:

The current capex costs shown in Figure 3 assume a ~2 MW (450 Nm^3/h) system for the current costs and a ~90 MW (20,000 Nm^3/h) system for the 2030 costs, consistent with the expected increase in system size based on increased production project sizes.

Objectives of analysis:

To show how electrolyzer capex costs are expected to evolve over time for different technologies. Figure 3 also shows the advantages, disadvantages, and potential applications of each technology.

Considerations and limitations of approach:

These costs represent the system capex costs, which includes the stack, transformer, rectifier, compressor for 30 bar compression, and purification/drying for 99.9% purity hydrogen. The costs do not include the cost of assembly, transportation, building, and installation. The reported values are based on industry estimates for electrolyzer capex costs developed by 3rd parties in 2020 using 2020 USD units. Forecasted electrolyzer capex values are rapidly evolving and may differ between sources. The Department of Energy is in the process of developing independent capex cost forecasts in a forthcoming publication.

Methodology 4: Levelized hydrogen production costs

Levelized hydrogen production costs were calculated based on the electrolyzer, reformation, and CCS industry data described in Methodology 3. These data are shown in Figure 2, Figure 11, and Figure 12. They are also used as inputs in other analyses across the report, including the total cost of ownership analysis (Methodology 10, Figure 15, 30), and the cashflow modeling (Methodology 17, Figure 23, 24).

Electrolysis levelized costs were calculated assuming an ~2MW (450 Nm^3/h) electrolyzer for current costs, an ~18 MW (4000 Nm3/h) electrolyzer for 2025 costs, and a ~90 MW (20,000 Nm^3/h) electrolyzer for 2030 and beyond. The levelized costs are all calculated using wind power from the NREL Annual Technology Baseline (ATB) 2022 report.[xxviii] In the case of grid power for electrolysis, a capacity factor of 95% was used to represent the reliability of grid power and the LCOEs were based on the EIA Annual Energy Outlook 2022 reference case Industrial Electricity prices.[xxix] Median performance by census region was used. To calculate the fully loaded costs, installed electrolyzer capex values are used, including assembly, transportation, building, and installation costs.

For reformation-based hydrogen, the capex costs collected using Methodology 3 were used to calculate levelized production costs. These costs assume $3/MMBtu natural gas prices, in line with natural gas price assumptions throughout this report.

To compare industry data sources, levelized production costs from Bloomberg New Energy Finance were also included in the error bars.[ii]

Key inputs and assumptions:

NREL ATB Class 5 onshore wind was used for the data shown in Figure 11 and the stacked bar charts in Figure 2. Class 1 and Class 9 onshore wind data was used to generate the error bars shown in Figure 11. Figure 2 shows electrolysis levelized production costs assuming alkaline electrolyzers, while Figure 11 shows levelized production costs for both technologies.

Objectives of analysis:

These calculations show that hydrogen produced via electrolysis is currently more expensive than reformation-based hydrogen but is expected to experience larger cost declines, due to future declines in renewables prices.

Considerations and limitations of approach:

These levelized costs use industry estimates for electrolyzer capex costs developed in 2020 using 2020 USD. Forecasted electrolyzer capex values and renewables LCOEs are rapidly evolving and may differ between sources.

The calculated levelized costs shown do not achieve the Hydrogen Shot by 2031. As discussed in the report, this gap between industry forecasts and DOE targets suggests that additional R&D innovation is required to meet the Hydrogen Shot.

Methodology 5: Hydrogen compression, liquefaction, and distribution costs

Gas compression and liquefaction

Gas compression costs are based on industry capex costs and compressor efficiencies collected through stakeholder interviews. Power costs are based on NREL Annual Technology Baseline Class 5 onshore wind and utility solar levelized costs and capacity factors.[iii]

Liquefaction costs are based on capex values for recent public announcements, combined with inputs from the Hydrogen Delivery Scenario Analysis Model at Argonne National Laboratory. [xxx,xxxi,xxxii]

Gas phase and liquid hydrogen trucking

The input costs to develop the gas phase and liquid hydrogen distribution levelized costs are from the Hydrogen Council report “Path to hydrogen competitiveness: a cost perspective.”[i] As described in Figure 5, these costs represent industry inputs. The levelized cost is then developed using the assumptions for distances, pressures, and throughputs described below.

Hydrogen pipeline (new build)

The hydrogen pipeline costs are based on the Hydrogen Delivery Scenario Analysis Model at Argonne National Laboratory using the input assumptions described below.

Dispensing costs

Dispensing costs were collected from 1) stakeholder interviews and from the Hydrogen Council using the methodology described in Methodology 3 and 2) from Argonne National Lab.

Key inputs and assumptions

Gas compression and liquefaction

See methodology section.

Gas phase trucking

Assumes hydrogen is compressed using a 50 tonnes per day compressor to 500 bar and transported using a drop-and-swap approach where a full tube trailer is swapped with an empty trailer, instead of emptying and refilling the same trailer. Range is based on regional variation in driver salaries, which represents the greatest cost variability and is the quantity that causes gas phase trucking cost to increase for longer distribution distances.

Liquid hydrogen trucking

Assumes hydrogen is liquefied using a 50 tonnes per day liquefier and transported to an offtaker with a leak rate of 6-15% during transfer to the offtaker. Leak rates were based on stakeholder interviews.

Hydrogen pipeline (new build):

Assumes hydrogen is compressed to 80 bar and transported in a newly built, dedicated hydrogen pipeline. Levelized cost range shown in Figure 5 is based on difference between high-cost regions (e.g., New England) and low-cost regions (e.g., Great Plains)

Dispensing costs

Assumes station dispenses 700 kg per day at 700 bar, with variability in station utilization from 15-20% to 70+%. Range of utilization considers both regions with limited adoption of H2-based road transport and earlier adopter regions with greater H2-based road transport penetration rates.

Objectives of analysis

Illustrate the levelized costs of midstream infrastructure and the relative costs of various midstream pathways as well as the boundary conditions under which each type of hydrogen distribution might be preferred.

Considerations and limitations of approach

Gas compression

Levelized costs are highly dependent on the type of electricity used and the capacity factor of the hydrogen production pathway. For production from electrolysis with variable renewables, a low-cost variable renewable source is typically used to power the compressor, matching the up-time of the electrolyzer. For higher capacity factor production, such as reformation-based hydrogen with carbon capture, higher cost grid electricity is often used to power compressors to allow higher up-time.

Gas phase trucking

This approach assumes gaseous hydrogen is distributed using a drop-and-swap approach where a full trailer is delivered to the offtaker and the empty trailer from the previous trip is removed. A drop-and-swap approach limits time on site and therefore driver salaries because the driver does not have to wait for the tube trailer to empty. The alternative pressure transfer approach where the driver transfers the hydrogen from a tube trailer to an on-site storage unit, is a slower approach, increasing distribution costs.

Liquid hydrogen trucking

An important consideration of liquid hydrogen trucking is the leak rate during transfer from a cryogenic tanker to the on-site storage unit. The leak rate will lower the amount of hydrogen that can be delivered in one trip, effectively increasing the levelized cost.

Hydrogen pipeline (new build):

At scale, multiple sizes of hydrogen pipeline will be required. The 600 tonnes per day pipeline size represents distribution between a small number of producers and offtakers. A pipeline backbone, analogous to the U.S. natural gas network or the European Hydrogen Backbone project, would require pipelines that can transport several thousand tonnes per day over longer distances. The difference in costs is illustrated in Figure 5.

Dispensing costs:

Since dispensing costs are primarily related to the capex to build the hydrogen refueling station and supporting infrastructure, the utilization rate is a significant driver of costs. For the use case in these calculations, Class 8 trucks, the longer driving range allows for fewer, higher utilization stations along major highway corridors compared to potential smaller-scale road transport applications. As such, high utilization was assumed.

Methodology 6: Hydrogen storage costs

Hydrogen storage capex costs are reported in Figure 6, along with calculated levelized costs and the tradeoffs between storage methods. These storage costs are used in the cashflow modeling analysis (Methodology 17, Figure 23,24), and are also shown in the multimodal pathways figure (Figure 10).

<u>Compressed gas tank storage and liquid hydrogen storage</u>

The Hydrogen Council report “Path to hydrogen competitiveness: a cost perspective” was used for compressed gas tank storage and liquid hydrogen storage capex and opex costs.[i] These data are from industrial sources using analogous approach to Methodology 3. The levelized costs were calculated with an assumed lifetime, utilization, pressure, and volume described below.

<u>Salt cavern and lined hard rock storage</u>

Salt cavern storage and lined hard rock storage levelized costs were calculated using the capex values reported in the Argonne National Laboratory report “System Level Analysis of Hydrogen Storage Options” with the Hydrogen Delivery Scenario Analysis Model. [xxxiii, iii] See below for the detailed input assumptions.

Key inputs and assumptions:

Storage costs do not include the cost of compression or liquefaction, which is included in the distribution costs shown in Figure 5. Assumptions specific to each storage type are included below:

- Compressed gas tank storage: Assumes that 950 kg H2 are stored at 500 bar, with 1 cycle per week. A 7% WACC and 20-year life are assumed.
- Liquid hydrogen storage: Assumes 50 TPD capacity, cycled 1 time per week, with a 7% WACC and 20-year life.
- Salt cavern storage: Assumes 80 bar storage pressure with sufficient capacity to store 7 days of throughput from a 600 TPD dedicated H2 pipeline. The geologic storage gas is assumed to be ~40% by volume, so the utilization of storage capacity is ~60%.
- Lined Hard rock storage: Uses analogous assumptions to salt cavern storage, but storage pressure is assumed to be 150 bar.

Objectives of analysis:

Highlight that geologic storage has the lowest cost but is geographically constrained, while gaseous tank storage and liquid storage are not geographically constrained but are higher cost.

Outputs:

Geologic storage, using both salt caverns and lined hard rock caverns, are the lowest cost hydrogen storage option, but are geographically constrained. As such, the locations of these formations will affect where early hydrogen production projects are developed, particularly for electrolysis-based production with variable renewable sources. Liquid phase storage has a low levelized cost as well but can only store hydrogen for up to 10 days and requires expensive and energy-intensive liquefaction. Compressed gas tank storage is the highest cost, but is also the most flexible, making it appropriate for small scale, distributed use cases.

Considerations and limitations of approach:

Compressed gas tank storage

Cost estimate is for Type 1 stationary storage. Various gas tank storage methods have a wide range of costs. Maturation of gas storage supply chains and narrowing of safety parameters could bring lower gas tank storage prices to market by 2030. Over-the-road gas tanks must also be tested annually, which is not included in the costs here for stationary storage. Readers should evaluate re-testing and recertification as an added cost.

Liquid hydrogen storage

Liquid hydrogen allows storage of larger quantities of hydrogen in a smaller space than gaseous storage, making it ideal for large quantities when geologic storage is not available and for long-distance distribution. However, the time that hydrogen can be stored is a liquid is limited due to hydrogen boil off.

Salt cavern storage

Cavern storage is typically one of the lowest cost storage options and has significant economies of scale effects, making it ideal for hydrogen hubs and areas large production/offtake capacity. However, caverns are geographically limited and storage of other gases, including natural gas and CO2, limit availability.

Lined hard rock storage

The same tradeoffs for salt cavern storage are also observed for lined hard rock storage.

Methodology 7: Hydrogen feedstock total addressable market (TAM)

The potential hydrogen feedstock market size was calculated under two scenarios and shown in Figure 7:

- H2 feedstock TAM: Represents the market size for clean hydrogen feedstocks in each end use; calculated by multiplying the clean hydrogen in the “Net zero 2050 – high RE” scenario by the midpoint in the range of willingness to pay by end use reported in the DOE National Hydrogen Strategy and Roadmapiii; dispensing costs are subtracted from the road transport TAM and market size with full adoption
- H2 feedstock TAM with full adoption: Represents the maximum market size if the hydrogen-based solution had 100% share of each end use

These two quantities allow readers to understand the potential associated with each end use based on surpassing or not meeting the demand forecast. To calculate the TAM for each end use, the willingness to pay for clean hydrogen in each end use was multiplied by a hydrogen demand. The detailed methodology is described in Figure 26.

Profitability[1] criteria for post-PTC electrolysis at full utilization

End use	H2 feedstock TAM approach	H2 market size with full adoption approach	Sources
Ammonia	H2 demand from National Strategy * WtP	Same as TAM approach, using National Strategy assumption of 100% clean hydrogen penetration	National Hydrogen Strategy
Refining	H2 demand from National Strategy * WtP	Same as TAM approach, using National Strategy assumption of 100% clean hydrogen penetration	National Hydrogen Strategy
Steel	H2 demand from National Strategy * WtP	National Strategy assumption that H2 can decarbonize 10-20% of steel demand, scaled to full potential based on total forecasted U.S. steel demand	National Hydrogen Strategy, DOE Industrial Decarbonization Roadmap
Methanol	H2 demand from National Strategy * WtP	National Strategy assumption that H2 can decarbonize 50% of methanol demand, scaled to full potential based on total forecasted U.S. methanol demand	National Hydrogen Strategy, IEA and OECM, "The Future of Petrochemicals Towards more sustainable plastics and fertilizers," International Energy Agency, France, October 2018
Road transport[1]	H2 demand from National Strategy * (WtP – dispensing costs)	Projected Class 8 long-haul and regional truck miles driven * fuel efficiency * (WtP – dispensing costs)	National Hydrogen Strategy, EIA Annual Energy Outlook 2022
Aviation fuels	(H2 for biofuels demand from National Strategy*biofuels WtP) + (H2 for PtL demand from National Strategy*PtL WtP)	Assumes ~39B gallons in 2050 (100% penetration) based on SAF Grand Challenge, scaled down in 203 and 2040 based on U.S. jet fuel demand	SAF Grand Challenge, EIA Annual Energy Outlook 2022
Maritime fuels	H2 for projected clean ammonia and methanol maritime fuel * ammonia and methanol WtP	Overall projected U.S. maritime fuel demand (in EJ) * WtP	Mission Possible Project report "A Strategy for the Transition to Zero-Emission Shipping"
NG blending for building heat	Zero demand	Total forecasted residential/commercial heating demand converted to hydrogen volume using specific energy * WtP	National Hydrogen Strategy, EIA Annual Energy Outlook 2022
Industrial heat	H2 demand from National Strategy * WtP	National Strategy assumption that H2 can decarbonize 20-50% of industrial heat, scaled to full potential	National Hydrogen Strategy
Power – 20% H2 (Combustion)[2]	H2 demand from McKinsey Power Model output * power WtP	Total forecasted power demand converted to 20% hydrogen volume using specific energy and heating values * WtP	McKinsey Power Model, EIA Annual Energy Outlook 2022

1. H2 feedstock TAM uses H2 demand from the DOE National Hydrogen Strategy and Roadmap assuming both medium- and heavy-duty trucks; H2 market size with full adoption is based on energy usage from Class 8 long-haul and regional trucks, which represent the significant majority of all medium- and heavy-duty truck energy consumption
2. Willingness to pay is based on high-capacity factor firm power
NOTE: Willingness to pay (WtP) is based on the mid-point of the ranges reported in the DOE National Hydrogen Strategy and Roadmap

Figure 26: Methodology for calculating TAM, leveraging public reports and projections[xxix,xxxiv,xxxix,xxxv]

Key inputs and assumptions:

The willingness to pay for clean hydrogen and hydrogen demand forecasts were based on the DOE National Clean Hydrogen Strategy and Roadmap[x] forecasts, except for maritime demand. To calculate the monetary value of the hydrogen feedstock opportunity in each end use, the midpoint of the willingness to pay was multiplied by the relevant hydrogen demand. In the case of road transportation, dispensing costs were subtracted from the willingness to pay.

Hydrogen demand from maritime end uses was calculated based on the University Maritime Advisory Services report "A Strategy for the Transition to Zero-Emission Shipping: An Analysis of Transition Pathways."[xxxvi] Global zero emission fuel and the split between ammonia and methanol-based fuel was scaled to U.S. demand based on the percentage of global maritime usage in U.S. ports. Hydrogen demand was calculated based on the hydrogen content in methanol and ammonia fuel demand forecast.

To calculate the clean hydrogen feedstock TAM with full end use adoption, the total future demand for each end use was needed. The sources listed in Figure 26 were used for these future demand forecasts, consistent with the sources used in the DOE National Clean Hydrogen Strategy and Roadmap. For hydrogen demand from maritime fuel, a process analogous to the approach described above was used, except with the total forecasted maritime fuel demand rather than the zero-emission fuel demand forecast.

Objectives of analysis:

Evaluate illustrative market size and potential growth for H2 as a feedstock in various end uses.

Considerations and limitations of approach:

In end uses with multiple decarbonization options (e.g., transportation, steel, power, heat) there is inherent uncertainty in the clean hydrogen penetration rate, which will affect the overall TAM. There is also inherent uncertainty in the long-term projections for total end use market size. Finally, the willingness to pay by end use may vary over time and will vary on a project-by-project basis based on project-specific breakeven economics and willingness to pay a green premium.

Methodology 8: Hydrogen Project and Investment Tracker

The data shown in Figure 8 and Figure 9 was collected and shared from McKinsey's Hydrogen Project & Investment Tracker as of the end of 2022. The Hydrogen Project & Investment Tracker serves as a database for announced hydrogen projects and investments globally. The tracker has been built as part of McKinsey's partnership with the Hydrogen Council. Together with the Hydrogen Council, the Hydrogen Solution Insights team maintains the tracker to ensure high quality of data, which is leveraged in publications with the Hydrogen Council (e.g., in the Hydrogen Insights 2022 Report). The production projects capacity by target end use sector, shown in Figure 9, is based on announced plans and projects listed in the tracker.

The share of U.S. hydrogen production by pathway for electrolysis, reformation with CCS, and pyrolysis, shown in Figure 14, is also based on data from the tracker. The balance of production capacity is assumed to be reformation-based without CCS.

Key inputs and assumptions:

The Hydrogen Project & Investment Tracker includes publicly announced projects globally across the value chain: production projects (including different clean production pathways and excluding reformation-based hydrogen without carbon capture), distribution projects (e.g., conversion and re-conversion to a carrier, shipping, pipelines, trucking, hydrogen refueling stations), and end-use projects (e.g., steel, power generation, refining, sustainable fuels, derivatives). The tracker excludes small projects (< 1 MW installed capacity) and research projects.

Objectives of analysis:

Highlight the quantity and types of projects that are being announced, funded, and constructed, as well as the types of offtakers purchasing clean hydrogen.

Outputs:

Current production project announcements are 45% electrolysis by capacity and 55% reformation with carbon capture.
The electrolysis projects that are either at the FEED study stage or under construction represent 700 MW total electrolyzer capacity. Also see the DOE's electrolyzer tracker (link).

Considerations and limitations of approach:

Due to the Inflation Reduction Act tax credits, the number of new project announcements is rapidly increasing. While there will be attrition at each step in the project development pipeline, the rapid pace of project announcements suggests that the total announced clean hydrogen production capacity will increase in the near-term. The clean hydrogen projects by target end use sector are based on current announcements and partnerships, however, the target end use sectors for production projects may change over time as partnerships change, projects experience attrition, and new projects are announced.

Methodology 9: Hydrogen demand scenarios

Figure 13.1 shows six potential future hydrogen demand scenarios under different conditions. These scenarios are used as inputs in other analyses across the report, including the quantity of electrolyzers and iridium required (Methodology 12 and 13, Figure 18), jobs and gross value additions (Methodology 14, Figure 19), total hydrogen addressable market (Methodology 7, Figure 7), reformation and electrolysis production capacity split (Methodology 11, Figure 14), and required hydrogen value chain investments (Methodology 16, Figure 16).

While three scenarios are shown in Figure 13.2, a total of six scenarios were considered, serving various purposes:

- **Estimating current state trajectory:** Scenario (A) – "Business as usual (BAU) – current policy" scenario represents current state trajectory with IRA impacts but without additional commercialization interventions
- **Forecasting least cost pathways to meet decarbonization goals:** Net zero decarbonization scenarios forecast what it would take to reach net zero by 2050 under different levels of constraint
  on renewable and transmission capacity, and with/without achieving interim clean power by 2035.
  The specific scenarios are:
  - **Scenario (B)** – U.S. DOE National Clean Hydrogen Strategy Base Case
  - Net Zero 2050 – constrained renewable energy (RE): 1.1 TW[145] RE constraint – shown in Figure 14 (electrolytic vs. reformation-based hydrogen in the low RES case)
  - **Scenario (C)** – Net Zero 2050 – high RE: no constraint on RE capacity
  - Net Zero 2050 + 2035 clean power – constrained RE: 1.1 TW RE constraint with additional constraint that power sector achieves net zero by 2035
    - Model runs not shown in this iteration of the Clean Hydrogen Liftoff Report
  - **Scenario (C) in Figure 14.2** illustrating an additional ~2 MTTpa of power sector demand in 2030 due to clean grid constraints – Net Zero 2050 + 2035 clean power – high RE: no constraint on renewables capacity, but the power sector must achieve net zero by 2035
- **Exploring technology upside potential:** technology-specific spike scenarios (e.g., **Scenario (D)** – "Hydrogen technology spike") represent conditions for an optimistic-realistic upside case for that technology
- Highlighting Clean Grid considerations and its impact on clean hydrogen deployment: Including NREL 100% Clean Electricity by 2035 Study (**Scenarios E – All Options, F – Infrastructure**)

[145] 1.1TW constraint based on NREL Net Zero by 2035 report constrained scenario, in particular, two sensitivities regarding less solar and less wind. This cap is also similar to Net-Zero America 2050 report's constrained renewable cap of ~35/GW year

For each purpose, a non-power sector hydrogen demand scenario was developed. Power sector demand for Scenarios A, C, and D is based on the output of power sector modeling using the McKinsey Power Model to enable consistency across the Liftoff reports. All the Net Zero 2050 scenarios used the same hydrogen demand forecast. The hydrogen demand in Scenario A – BAU – current policy scenario and the Net Zero 2050 scenarios are based on the demand forecasts in the DOE National Hydrogen Strategy and Roadmap while the demand in the hydrogen spike case is based on the McKinsey Global Energy Perspective Accelerated Commitments case.[x,ii]

Scenario A – BAU – current policy demand scenario is derived from the DOE National Hydrogen Strategy and Roadmap as follows:[x]

- 2030: Only forecasted 2030 clean hydrogen demand from refining and ammonia demand are realized, representing a partial transition for both end uses
- 2040: Low end of the core range of estimates for long-term clean hydrogen demand is used
- 2050: High end of the core range of estimates for long-term clean hydrogen demand is used

Scenario C – The Net zero 2050 demand scenario is derived from the DOE National Hydrogen Strategy and Roadmap as follows:

- 2030: Refining and ammonia demand fully transition to clean hydrogen
- 2040: High end of the core range of estimates for long-term clean hydrogen demand is used
- 2050: 2050 clean hydrogen demand shown in Figure 12 of the DOE National Hydrogen Strategy and Roadmap

For the Net Zero 2050 scenario, the unconstrained / high renewables case is used. This case is consistent with the strong positioning of clean hydrogen to compete for clean electrons in the near-term based on PTC-driven favorable production economics and in the long run by the ability to avoid long grid interconnection queues. The Clean Grid 2035 scenario is also shown in Figure 13.1 and can be explored further in the NREL Clean Grid 100% Clean Electricity by 2035 Study.

Key inputs and assumptions:

Scenario (A) – Business as Usual (BAU) – Current Policy

Includes the IRA and assumes that, despite the additional funding for clean hydrogen, the current commercialization challenges are not overcome, holding back industry growth. Ammonia and oil refining drive demand through 2030 with significant growth in fuel cell-based road transport post-2030.

Scenario (B) – U.S. DOE National Clean Hydrogen Strategy – Base Case

Pulled from report Figure 12, which depicts potential scenarios for end-use of clean hydrogen in 2030, 2040, and 2050, enabling at least 20 MMT per year by 2040 and 50 MMT per year by 2050.

Scenario (C) – Net zero 2050 – High Renewables

Includes the IRA and assumes that the expansion of the hydrogen industry advances in line with a net zero by 2050 economy unconstrained by renewables deployment. Ammonia and oil refining completely transition to clean hydrogen by 2030 and post-2030 fuel-cell based road transport and aviation demand accelerates more rapidly.

Scenario (D) – Hydrogen spike case

Includes the IRA and assumes that clean hydrogen technologies advance more quickly than other decarbonization technologies – particularly LDES and CCUS, causing increased demand from all end uses. Increased 2030 power sector demand due to IRA incentives combined with slower LDES and CCUS development.

Scenarios (E), (F) - can be explored further in the NREL Clean Grid 100% Clean Electricity by 2035 Study

Objectives of analysis:

This analysis lays out the potential future hydrogen demand for three types of scenarios, forming the basis for additional analysis throughout the report on the implications and requirements associated with meeting this level of demand.

Considerations and limitations of approach:

As discussed in the report text, there is uncertainty over the role of clean hydrogen for some end uses, such as power and building heat. Other recently published reports forecast a larger role for hydrogen in these end uses, which is discussed in Chapter 3.

Methodology 10: Total cost of ownership (TCO) analysis

The overall methodology for calculating total costs of ownership (TCOs) by end use is based on the approach outlined in the Hydrogen Council's report "Path to hydrogen competitiveness: a cost perspective," with some modifications.[i] This analysis compares the TCO of electrolytic hydrogen applications against specific low-carbon and conventional alternatives. For example, fuel cell electric trucks versus diesel trucks.

While the Hydrogen Council report analyzed 35 applications, a subset is shown here to understand the effect of the H2 PTC. For each hydrogen application and its competing alternatives, a comprehensive TCO trajectory was developed to detail the relevant cost components, cost-reduction drivers were determined, and the break-even point was identified between competing solutions. This was done via an independent third-party clean team who collected, aggregated, and processed data from participating Hydrogen Council members, producing anonymized cost estimates by application. In a limited number of use cases where insufficient internal data were available, such as in developing the cost trajectory for aviation synfuels, external projections were used.

Subsequently, the H2 PTC was introduced to the analysis at the maximum $3/kg value, consistent with the low carbon intensity of electrolytic hydrogen. A post-PTC (after credit expiration) price floor of $0.4/kg was used based on the willingness to pay for hydrogen in gas blending and the power sector, which could act as large volume offtakers to prevent the post-PTC (expiration) price from becoming negative. Additionally, natural gas price assumptions were aligned with the other analyses in this report, assuming $4.8/MMBtu current prices that linearly decrease to $3/MMBtu by 2030 and onwards. The specific assumptions by end use are discussed below:

- **Refining:** Direct LCOH comparison of conventional reformation-based hydrogen without carbon capture and electrolytic hydrogen. Conventional hydrogen costs were based on Hydrogen Council projections for SMR-based hydrogen production.
- **Ammonia (electrolytic hydrogen):** Comparison between 750 kt p.a. conventional ammonia plant with SMR on-site production and analogous plant using on-site electrolytic hydrogen

- **Steel – new build DRI:** 2 MMT p.a. steel plant using 60% DRI-based green steel with scrap EAF. Electrolytic hydrogen used as the reductant, assuming a minimum of $0.4/kg LCOH after H2 PTC.
- **Chemicals – methanol:** 440 kt p.a. methanol plant. Carbon feedstock sourced from direct air capture for e-methanol or natural gas (via syngas route) for conventional alternative. Assumes minimum of $0.4/kg LCOH after H2 PTC and $3/MMBtu natural gas price by 2030.
- **Heavy duty truck:** Ranged using Hydrogen Council and NREL's TEMPO model. For Hydrogen Council, a 40-ton weight class heavy duty truck traveling 90,000 miles/year refueled at 700 bar using electrolytic hydrogen; assumes minimum of $0.4/kg LCOH, $2/kg H2 LCFS credit in California, Oregon, and Washington. Diesel price comparison is from the EIA Annual Energy Outlook.
- **Sustainable Aviation Fuel (SAF):** Electrolytic hydrogen and CO2 captured from industrial processes used with a Fischer-Tropsch process to synthesize SAF. Assumes minimum of $0.4/kg LCOH after H2 PTC and jet fuel prices from EIA Annual Energy Outlook.
- **Container ships:** Large container ship (~15,000 TEU) traveling 86,000 miles per year using e-methanol from DAC.
- **High-capacity firm power generation:** Comparison between 800 MW CCGT power generation using 100% hydrogen feedstock and 100% natural gas feedstock. Assumes 61% efficiency, 74% load factor, and $3/MMBtu natural gas price by 2030.
- **Lower-capacity factor power - fuel cell:** Modeled use cases are based on a scaled H2 Hub with open access pipelines in 2035. Hydrogen combustion was not analyzed for lower-capacity factor power in this Liftoff report.
- **Long duration energy storage:** Hydrogen is the primary technology expected to provide seasonal shifting for applications in need of 160+ hours duration in addition other end-uses (e.g., industrials). However, configurations like Hydrogen fuel cells with salt cavern storage (H2+Salt) have been evaluated as a technology to provide Multi-day LDES of approximately 48 to 120 hours. Hydrogen projects for Multi-day LDES would have large minimum deployment sizes (1GW+) and require specific geological features (i.e., salt caverns). While LCOS today for H2+Salt is between $200-400/MWh, future costs are projected to be competitive with technologies listed above. Locations with Hydrogen Hubs would likely see improved economics. If Hydrogen meets projected costs, it could compete with other Multi-day LDES technologies and Natural Gas CT-CCS for peaking capacity. Hydrogen is particularly attractive where utilization rates are expected to be low. Insights drawn in part from Hunter, C. A., Penev, M. M., Reznicek, E. P., Eichman, J., Rustagi, N., & Baldwin, S. F. (2021). Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids. Joule, 5(8), 2077–2101. https://doi.org/10.1016/j.joule.2021.06.018

Objective of analysis

Evaluate changes to total cost of ownership (TCO) for several end uses based on hydrogen production with the PTC.

Key inputs and assumptions

Unless otherwise noted, ranges were developed in Figure 27 using variations in the price of fossil fuel or clean hydrogen feedstocks. Fossil fuel feedstock price ranges were based on the EIA Annual Energy Outlook 2022 low oil price and high oil price scenarios, including for natural gas, diesel, jet fuel, and heavy fuel oil.[iv]

Clean hydrogen feedstocks were assumed to be based on electrolytic hydrogen, with levelized production costs calculated using PEM or alkaline electrolyzers based on either Class 1 or Class 5 onshore wind power.[iii]

For the current TCOs, a ~2 MW (450 Nm3/h) electrolyzer was used and for 2035 values a ~90 MW (20,000 Nm3/h) electrolyzer was used. Several end-use specific assumptions were also made:

- **Steel:** The incumbent technology TCO range is based on the TCO for BF-BOF and EAF steel
- **Heavy duty trucks:** The ranges shown include both the TCO calculated in this report using data from the Hydrogen Council as well as runs from the National Renewable Energy Laboratory's TEMPO model. Current runs of the TEMPO model do not contain the PTC in their existing scenarios but were instead modified to include hydrogen fuel prices under PTC-assumptions provided by the Hydrogen Council.
- **Sustainable aviation fuel (SAF):** Hydrogen TCO assumes carbon sourced using CO2 from either industrial processes or bio-based processes.
- **Container ships:** Hydrogen TCO range assumes both ammonia and methanol-based fuel

Outputs

Most projects are competitive | Some projects are competitive | Few projects are competitive

Demand type	End-use	Units	Incumbent tech.	Current TCO: Incumbent	Current TCO: Clean H_2 tech (with PTC)	2035 TCO: Incumbent	2035 TCO: Clean H2 tech. (post-PTC expiration)
Industry	Refining[1,2]	$ / kg	High CI H2	0.9-1.3	0.4-1.3	0.9-1.4	1.3-1.6
Industry	Ammonia (via electrolysis)[1,2]	$ / tonne	High CI ammonia	300-350	200-385	300-400	380-450
Industry	Steel – new build DRI[2,3]	$ / tonne	BF-BOF, EAF steel	450-465	470-510[7]	450-460	495-510
Transport	Heavy duty truck with LCFS[4]	$ / mile	Diesel truck	1.4-1.6	1.3[8]-2.6[9]	1.4-1.7	1.1[8]-1.5[10]
Transport	Heavy duty truck[4]	$ / mile	Diesel truck	1.4-1.6	1.5[8]-2.7[11]	1.4-1.7	1.3[8]-1.6[12]
Transport	Sustainable Aviation Fuel (SAF – RWGS + FT pathway)[1,2,5]	$ / gal	Jet A fuel	1.9-3.4[14]	3.1-4.5[13]	2.4-4.0[14]	2.2-2.6
Transport	Container ships[1,2,6]	$ / year	Heavy fuel oil ship	22-28k	29-39k[15]	21-34k	35-44k[15]
Gas replacement	High-capacity firm power gen – 100% H2 (Combustion)[1,2]	$ / MWh	Natural gas CCGT	31-33	36-80	31-34	75-95
Gas replacement	High-capacity firm power gen – 20% H2 (Combustion)[1,2]	$ / MWh	Natural gas CCGT	31-33	34-36	31-34	37-38
Gas replacement	Lower-capacity factor power – H2 fuel cell[16]	$ / MWh	Natural gas CCGT	160-330	N/A	160-340	180-290
Gas replacement	Long duration energy storage[17]	$ / kw	Range of tech	1100 - 1400	1800	TBC	500-600

Ranges primarily represent varying fossil fuel price assumptions and clean hydrogen input assumptions

1 Range base on EIA Annual Energy Outlook 2022 low oil / high oil scenario
2 Range based on electrolytic hydrogen range with Class 1 or Class 5 onshore wind and PEM or alkaline electrolyzers
3. Range based on BF-BOF and scrap EAF TCO
4 Range based on Liftoff report methodology and VTO / HFTO model, no other credits assumed
5 Carbon sourced using carbon captured from industrial processes
6 Range includes both methanol and ammonia fuel
7 Range includes value calculated for H2 DRI-EAF steel reported by Zang, Guiyan, et al. "Cost and Life Cycle Analysis for Deep CO2 Emissions Reduction for Steel Making: Direct Reduced Iron Technologies." *Steel Research International*.
8 Liftoff report model with LCFS and H2 PTC; adjusted for FCEV credit ($40k), Refueling station credit ($100k)
9 Derived from NREL TEMPO model (2021) – Central scenario, adjusted for PTC, LCFS, FCEV credit ($40k), Refueling station credit ($100k) with driver cost and stack replacement added
10 Derived from NREL TEMPO model (2035) adjusted for PTC-driven cost-downs bot no active credit, LCFS, FCEV credit ($40k), Refueling station credit ($100k) with driver cost and stack replacement added

11 Derived from NREL TEMPO model (2021) – Central scenario, adjusted for PTC, FCEV credit ($40k), Refueling station credit ($100k) with driver cost and stack replacement added
12 Derived from NREL TEMPO model (2035) adjusted for PTC-driven cost-downs bot no active credit, FCEV credit ($40k), Refueling station credit ($100k) with driver cost and stack replacement added
13 CO2 conversion with RWGS + FS and ~1.8 kg H2 / gal SAF, adjusted for H2 prices under the PTC. Scenario does not include other fuels credits.
14 Based on EIA Annual Energy Outlook 2023 and 2035 - reference case vs high oil price case.
15 Ammonia: 29k/year (current, low), 37k/year (current, high), 39k/year (2035, low), 44k/year (2035, high); Methanol: 34k/year (current, low), 39k/year (current, high), 35k/year (2035, low), 39k/year (2035, high)

16 Use cases require successful, scaled H2 Hub with open pipeline access
17 Insights drawn from Hunter, C. A., Penev, M. M., Reznicek, E. P., Eichman, J., Rustagi, N., & Baldwin, S. F. (2021). Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids. Joule, 5(8), 2077–2101. https://doi.org/10.1016/j.joule.2021.06.018
Source: EIA Annual Energy Outlook 2022, NREL Annual Technology Baseline 2022, Hydrogen Council, McKinsey Hydrogen Insights Analysis, NREL TEMPO Model (Central Scenario), ANL Autonomie Model

Figure 27: Hydrogen is not always 'in the money' and in some cases faces fierce competition with fossil incumbents. Hydrogen is a breakeven decarbonization option in locations favorable for electrolysis when fossil fuel prices follow a BAU scenario, but either low fossil fuel prices or less favorable electrolysis locations could limit breakeven

Methodology 11: Reformation and electrolysis hydrogen production split

The split between reformation-based hydrogen and electrolytic hydrogen was calculated using the McKinsey Power Model and shown in Figure 14. See the [Modeling appendix] for details on the McKinsey Power Model methodology. This production pathway split was also used as input in other analyses across the report, including the required hydrogen value chain investments (Methodology 16, Figure 16) and the jobs and gross value additions (Methodology 14, Figure 19).

Key inputs and assumptions:

Electrolyzer and reformation input costs were consistent with the costs referenced in Methodology 3 and 4. Two iterations of the Net zero 2050 scenario were included – one with no constraints on renewable energy sources (RES) development ("high RES") and one with a cap of 1.1 TW through 2050 ("low RES"). Non-power sector hydrogen demand was input consistent with the Net zero 2050 scenario shown in Figure 13. Power sector hydrogen demand was calculated by the McKinsey Power Model based on the amount of hydrogen required to decarbonize the grid. A subsequent scenario was also analyzed imposing a clean grid by 2035 constraint with the same non-power sector hydrogen demand. The non-hydrogen assumptions described in the [Modeling appendix] were also used in this analysis.

Objectives of analysis:

Evaluate relationship between renewables expansion and the split of hydrogen production between reformation with CCS vs. water electrolysis.

Methodology 12: Supply chain analysis

For clean hydrogen to scale-up according to the demand scenarios shown in Figure 13, the associated supply chain will also need to scale. While some aspects of the supply chain are already at-scale (e.g., steam methane reforming), other areas such as electrolyzers, tube trailers, hydrogen storage, and carbon capture will need to scale significantly.

The potential supply chain constraints across the clean hydrogen value chain expected in 2025, shown in Figure 17, were compiled from a range of sources; building on and through discussions with the authors of the "Water Electrolyzers and Fuel Cells Supply Chain" report published by the Department of Energy in February 2022, complemented by insights from interviews with clean hydrogen industry experts. The heat map summarizes the risk level across several dimensions of potential vulnerability along the value chain, from raw materials availability, through to domestic construction & operations talent availability, for many of the key clean hydrogen technology components. These components are defined as follows:

- **Global raw materials availability:** The global abundance of critical material inputs required for production of the technology
- **Domestic sub-component supply base:** Current and planned U.S. capacity for production of sub-components (e.g., electrolyzer membranes, metal components for storage tanks)
- **Domestic equipment manufacturing capacity:** Current and planned U.S. capacity for production of final assembled equipment, relative to expected U.S. demand. Availability of global equipment supply: Current and planned global production of final assembled equipment, relative to expected global demand

- **Availability of global equipment supply:** Current and planned global production of final assembled equipment, relative to expected global demand
- **Diversity of global equipment supply:** Geographical breadth of active global suppliers for each component
- **Domestic technical & design talent:** Current and expected pipeline for U.S. based design and engineering expertise, including highly skilled positions such as university researchers
- **Domestic construction & operations talent:** Current and expected pipeline for U.S. based construction & operations expertise, including project management, planning, and regional field operations teams for installations of technology

One area of further focus was iridium required for PEM electrolyzer catalysts. The forecasted scale-up in PEM electrolyzer demand will increase demand for iridium, however, as a platinum group metal (PGM), iridium deposits are limited and only mined on a small scale. In this analysis, the required quantity of iridium was estimated based on PEM electrolyzer scale up and compared to current mining capacity.

Key inputs and assumptions

See methodology section for key inputs to supply chain analysis in Figure 17. The figure assumes rapid growth of the clean hydrogen industry, in line with projections covered elsewhere in this report. The risk levels are assigned assuming the current trajectory of trends for each component continues; for example, assuming that there are no external supply shocks that impact the availability of U.S. domestic manufacturing capacity for large diameter natural gas pipes.

To forecast the demand for iridium, 25% of the production capacity shown in Figure 18 was assumed to be met by PEM electrolyzers. This assumed PEM share likely represents a conservative assumption – the Hydrogen Project & Investment Tracker described in Methodology D shows that ~1/3 of announced electrolysis production globally uses PEM electrolyzers and, as described in Section 3c, PEM electrolyzers in the U.S. may achieve a higher share than globally. Nonetheless, the quantity of iridium required is significant. To calculate the total iridium required, an iridium catalyst loading of 0.25 kg/MW electrolyzer was assumed and the 2021 global iridium supply of 8.1 tonnes was used.[xix]

Objectives of analysis

To meet the forecasted rapid acceleration in clean hydrogen demand, the supply chain will need to expand rapidly as well. This analysis shows the near-term supply chain risks across the value chain, which if unaddressed, could constrain scale up of clean hydrogen. Further analysis was also completed to assess the amount of iridium required to scale PEM electrolyzers, motivating the need for additional R&D innovations.

Considerations and limitations of approach

The heat map shown in Figure 17 represents potential vulnerabilities in 2025; longer term vulnerabilities should be assessed separately. Given the inherent interrelated nature of clean energy technologies, unexpected shifts in the demand or supply patterns from other industries (e.g., oil & gas, direct air capture, renewables) may impact this assessment. The assessment focuses on 2025 to minimize the uncertainty introduced through taking this approach. It also does not assume any breakthrough technology innovations; It also does not assume any breakthrough technology innovations; for example, no significant reductions in the Iridium loading requirement for PEM electrolyzer production are assumed.

While global raw material shortages are not currently an issue, the global abundance of certain materials, particularly platinum group metals (PGMs), may be stressed by electrolyzer production in 2030 and beyond. While each mining area has a different mix of PGM concentrations (e.g., 40% vs 50% platinum), the mining rates for these metals are often coupled – and as such, the feasibility of ramping up production for only a subset of these metals is impractical.[xix] A PGM refinery could hypothetically be built in the U.S. for raw material security, but the low PGM reserves (~5% of global reserves) and small annual production (representing ~5% of global production in 2021), would make the economics challenging.[xxxix,xi]

In addition to iridium, U.S. electrolyzer manufacturers will need graphite, yttrium, platinum, and strontium; the U.S. depends heavily on foreign supply for all these materials, most of which cannot be found domestically in sufficient quantities. This reliance on foreign suppliers could hinder growth of U.S. based electrolyzer manufacturing.

Methodology 13: Electrolyzer production capacity ramp up

Electrolyzer production capacity data shown in Figure 18 was collected and shared from McKinsey's Hydrogen Insights Electrolyzer and Fuel Cell OEM Supply Tracker as of the end of 2022. The tracker serves as a database for announced manufacturing production capacity globally. The tracker has been built as part of McKinsey's partnership with the Hydrogen Council. Together with the Hydrogen Council, the Hydrogen Solution Insights team maintains the tracker to ensure high quality of data, which is leveraged in publications with the Hydrogen Council (e.g., in the Hydrogen Insights 2022 Report).xvi

The U.S. production capacity required by year, shown in Figure 18, is based on meeting the Net Zero 2050 – high RE hydrogen demand scenario shown in Figure 13 and the electrolysis vs. reformation production split shown in Figure 14 with domestic electrolyzer manufacturing.

Key inputs and assumptions

The capacity ramp-up curve shown here is based on an upper production bound to produce ~10 MMT clean hydrogen from electrolysis by 2030 (meeting Net Zero 2050 – high RE hydrogen scenario), based on Figure 13 and Figure 14. The average size of an electrolyzer production plant is assumed to be 1.5GW/year, based on the average size of advanced new production facilities under construction today in the EU and China. The average US production facility is currently smaller than this size but is expected to increase over time to align with the facility size in more well-developed hydrogen economies in EU. Each new facility is modeled using a gradual production ramp up over time to simulate learning curves and additional downtime in the first couple of years. Each facility is assumed to operate at 40% of total capacity during Year 1, 70% of total capacity in Year 2, and 100% (i.e., full capacity) by Year 3.

Objectives of analysis

There are only a few small-scale electrolyzer manufacturers in the U.S., so this analysis highlights the rapid and significant ramp-up in capacity that will be required to meet projected demand and avoid an electrolyzer bottleneck. It also highlights that post-PTC-expiration, the U.S. will likely need to export electrolyzers to fully utilize electrolyzer capacity.

Considerations and limitations of approach:

This analysis assumes that there is no constraint on the scale up of new electrolyzer production facilities (i.e., limited labor availability or component supply chain delays), and that each plant follows the same 40-70-100% annual production ramp up over the first three years of operation. It also does not consider the option of extending or increasing capacity of existing production facilities, nor does it account for long periods of production downtime. The model does not account for import or export of electrolyzers and does not directly consider the economics of each production plant; if demand for new electrolyzers in the US declines post-PTC expiration. There is a risk of stranded production capacity, which may in turn be reflected in the scale-up plans for each facility.

Methodology 14: Jobs and GVA calculations

Jobs and Gross Value Additions (GVA) calculations were completed by Vivid Economics using the I3M economic model with input-output tables developed by IMPLAN.[xli] Inputs were based on the required cumulative capex investments through 2030 and 2050 calculated using the Hydrogen Council-based investment methodology described in Methodology 16, with required investments segmented by value chain step and further by production type, storage, and distribution type, and by end use. Investments to build out low-carbon electricity production were also included. Each type of investment was assigned one of 546 IMPLAN sectors. The IMPLAN application was then used to derive the socioeconomic impacts (jobs and GVA) per $1 million of capital investment within the respective sector and then multiplied by the specific required capex investment. To calculate the number of active hydrogen asset install, OEM, and capex-driven jobs in 2030, the cumulative capex investment through 2030 was segmented by year using a linear ramp rate. The relationship between capex investment in each of these sectors and the associated opex once the asset is built was also determined using the IMPLAN sectors to calculate the opex jobs and GVA impact.

Key inputs and assumptions:

The required capex investments were calculated using the Hydrogen Council-based investment methodology described in Methodology 16. The IMPLAN datasets are sourced from a variety of government databases, including from the Bureau of Economic Analysis and Bureau of Labor Statistics. IMPLAN also develops estimates for non-disclosed data and data for non-census and non-survey years as well as disaggregating data into finer geographics scales and industry detail. To calculate the active hydrogen asset install, OEM, and capex-driven jobs in 2030, a linear ramp rate for capex investment was used through 2030.

Objectives of analysis:

Illustrate scale of workforce opportunity across the clean hydrogen economy.

Considerations and limitations of approach:

Direct employment benefits estimate the number of jobs supported by capital expenditures and operating expenditures to maintain those assets. Indirect jobs are jobs supported by the share of capital or operating expenditure directed to spending on goods and services in the wider domestic supply chain. Finally, induced jobs are supported by spending in the wider economy from employees involved in developing and operating the new facility, as well as those across the domestic supply chain supporting this activity.

GVA can be defined as the measure of the value of goods and services produced in an area, industry or sector of an economy. It is comparable to GDP but does not include taxes or subsidies.

Methodology 15: Global Hydrogen Flows

The global levelized production costs shown in Figure 21 and the export flows shown in Figure 22 are from the Hydrogen Council report “Global Hydrogen Flows: Hydrogen trade as a key enabler for efficient decarbonization.” The report methodology is reproduced below with minor modifications.[xlii]

The Global Hydrogen Flows Perspective is coauthored by the Hydrogen Council and McKinsey. To support the analysis, the Hydrogen Council developed a bespoke advanced-analytics optimization model that balances supply and demand across all regions and multiple carriers and end products. In total, the Global Hydrogen Trade Model optimizes across 1.5 million potential trade routes. The demand view is aligned with a net-zero pathway developed by both organizations, with projections in line with global climate targets modeled for 2025, 2030, 2040, and 2050. The levelized production costs are developed by the Hydrogen Council based on industry data using the same methodology described in Methodology 3. The flows shown in Figure 22 are based on the reference case scenario, which considers economically efficient decarbonization with minimized overall system costs. The scenario purposefully does not consider current geopolitical trade limitations to be a factor in the long run.

To better understand the energy transition and the role of hydrogen trade, three other scenarios were developed to test the reference case scenario. These alternative scenarios evaluate the development of hydrogen trade if the decarbonization transition is delayed, if countries prioritize local supply chains and production, and if the world prioritizes renewable over low-carbon pathways. The report also assesses the impact of a no-trade scenario to understand the full benefits of trade on overall investments and costs. To review the effects of these scenarios, please refer to the full Hydrogen Council report.

Key inputs and assumptions:

The Hydrogen Council report uses industry data provided by Hydrogen Council members, as described in Methodology 3.[i]

Objectives of analysis:

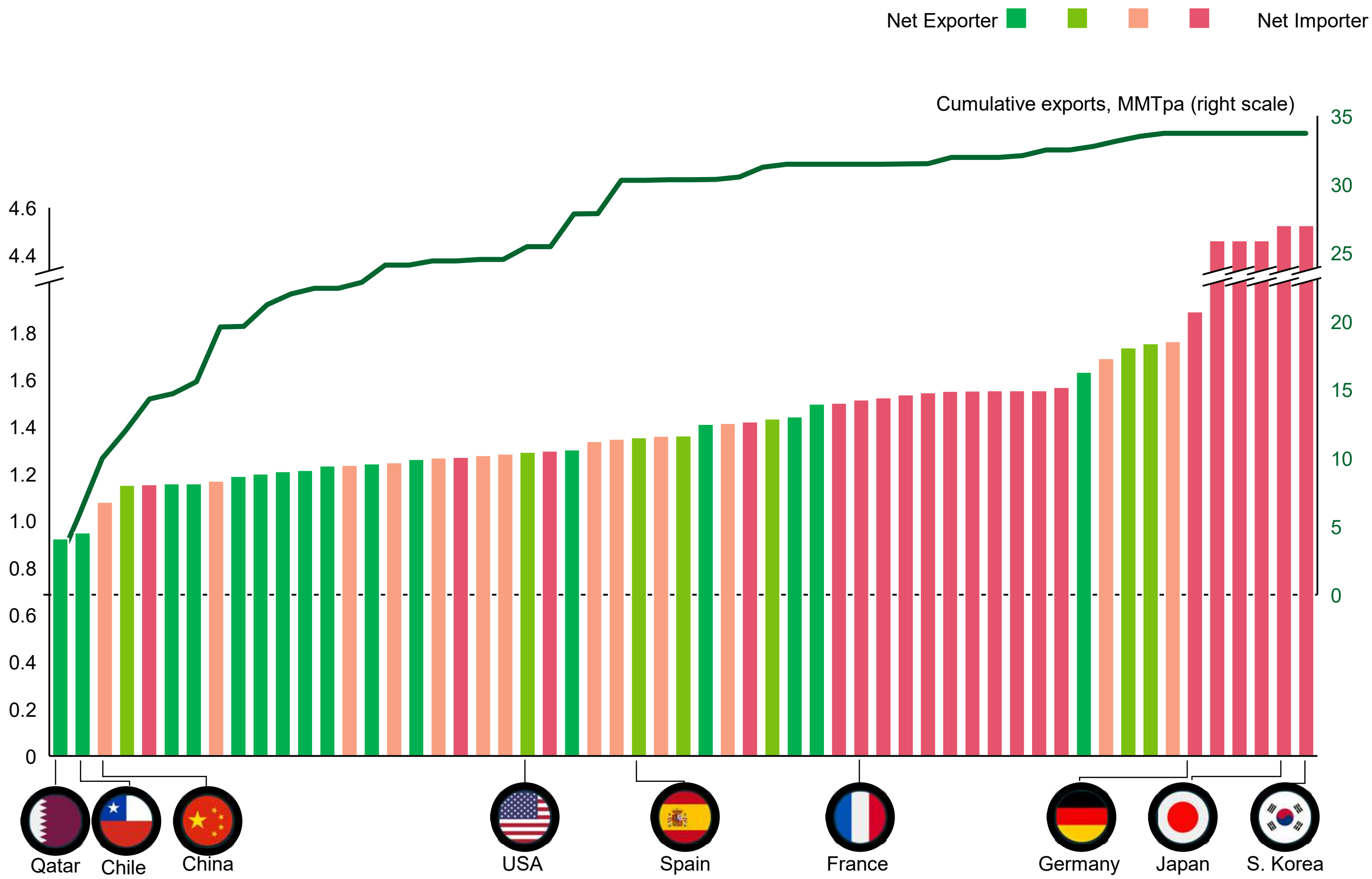
This analysis illustrates the pre-PTC cost-competitiveness of domestically produced hydrogen relative to the rest of the world. It also provides a 3rd party assessment of 2050 U.S. hydrogen export potential and global production cost competitiveness.

Considerations and limitations of approach:

The reference case scenario purposefully does not consider current geopolitical trade limitations to be a factor in the long run, although the optimization model allows us to flexibly model trade-route blockages and observe their impact. The projections of future trade flows are subject to many uncertainties. The Hydrogen Council report has tested the results relative to variations in input assumptions to find different analytical outcomes based on least-cost considerations. See the report for full details. These results serve to inform stakeholders, rather than to predict the future. In reality, (geo-)political considerations, existing assets, capabilities and capital, business decisions (for example, first movers, lock-in effects, and so on), and other factors will influence which trade routes will emerge, where hydrogen-production costs will fall fastest, and where uptake will keep pace with projections or fall behind.

Generally, the model does not take into account regulatory incentives such as EU Important Projects of Common European Interest (IPCEI) funding. Additionally, this analysis was done prior to the enactment of the Inflation Reduction Act (IRA) in the United States. The IRA's full extent and application is uncertain given that regulations are still being implemented. As such, the ultimate impact on trade flows is uncertain. If it were considered, the likely effect would be to make a portion of US production more competitive in the first decade—from 2022 to 2032—with unknown long-term impact on trade balances.

Cost of hydrogen production by market 2030 (without PTC)[1], $/kg



1. U.S. costs assume SMR-based hydrogen with CCS and $3 / MMBtu natural gas price; SMR facility capex (100k Nm^3 / h capacity): $215 million; CCS capex (100k Nm^3 / h capacity): $135 million
Source: Hydrogen Council

Figure 28: Third party analysis from the Hydrogen Council - Pre-PTC, the U.S. was not the least cost hydrogen producer relative to countries with faster permitting, less expensive labor, and extremely favorable conditions for renewables build-out; with the PTC, U.S. production is globally competitive, insulating the U.S. from import competition.[156] U.S. production costs are based on reformation-based hydrogen with CCS, aligned with Figure 12.

Methodology 16: Required investments across the hydrogen value chain

Required investments across the value chain, shown in Figure 16, were calculated using the method outlined in the Hydrogen Council report "Hydrogen for Net-Zero: A critical cost-competitive energy vector" and the hydrogen demand forecasts shown in Figure 13 for the Net zero 2050 – high RE scenario and the hydrogen spike case scenario. The production pathway split between electrolysis and reformation-based hydrogen from Figure 14 is also used to determine upstream production capex investment requirements and net new low carbon energy production investment requirements. The Hydrogen Council methodology is summarized below.

Hydrogen value chain direct investment requirement:

This report presents a novel view of the direct investments required to realize the projected hydrogen economy. It employs detailed hydrogen application total cost of ownership (TCO) models and hydrogen cost and investment data collected from Hydrogen Council Members through a clean team (please refer to "Path to hydrogen competitiveness" and "Hydrogen Insights" (from January 2021).i The analysis considers three main value chain steps: hydrogen production; hydrogen midstream infrastructure, including distribution, storage, and conversion; and end use infrastructure.

Hydrogen production

Estimates include the investments required to build out new electrolysis and reformation-based hydrogen 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 report derives 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 instance, fuel cells, hydrogen tanks, and refueling infrastructure are included. Other equipment includes turbines, generators, plant investment for conventional industrial feedstock uses such as ammonia and methanol, and new hydrogen applications like steel.

Key inputs and assumptions

Required investments were calculated based on the hydrogen demand scenarios described in Figure 14. 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 the Scenario Evaluation and Regionalization Analysis (SERA) model (National Renewable Energy Laboratory).[xliv]

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. 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.

Methodology 17: Cashflow model

The economics of production projects for a set of end uses was analyzed using a cashflow model developed as part of this report. The project economics were considered for electrolysis production and ATR-based reformation with carbon capture. Sensitivity analyses were also completed for a subset of end uses to understand the effect of key inputs such as customer willingness to pay, electricity and natural gas prices, as well as whether production and offtake were co-located.

Figure 24 also shows the production project economics once the PTC sunsets, both for existing projects that had used their 10-year PTC credit and for projects constructed after 2032 that were not eligible for the PTC. As such, project economics are shown for electrolysis and ATR-based production with carbon capture for projects that begin construction soon and those that begin construction in 2035. The following end uses were considered: (1) ammonia, (2) refining, (3) steel, (4) methanol, (5) road transport, (6) maritime, (7) natural gas blending for building heat, (8) industrial heat, and (9) high-capacity firm power generation (100% hydrogen combustion) Note that maritime fuels represent the hydrogen that is delivered to a biofuels or synfuels plant that produces clean maritime fuel.

A red, yellow, green color scheme is used in Figure 24 to show the post-PTC (after credit expiration) project economics by production method, project construction period, and end use. For existing projects, if the present value of total free cashflow is positive for the time period after the PTC can no longer be claimed, the end use is marked green. If the present value of the post-PTC total free cashflow is negative (after credit expiration), but a 25% reduction in capex and opex costs would result in a positive post-PTC total free cashflow (after credit expiration), the end use is marked as yellow. Otherwise, the end use is marked as red. For new projects starting construction in 2035, an analogous approach is used, but the cutoff used is a 7% IRR for the life of the project (both levered and unlevered).

Additionally, Figure 23 shows the effect of clean electricity prices on the willingness to pay cutoff where existing projects retain a positive post-PTC (after credit expiration) free cashflow and new projects clear the IRR threshold – if electricity prices decrease, producers will be able to remain profitable selling to offtakers with lower willingness to pay.

Objective of analysis:

Illustrate the hydrogen production project economics and their dependence on key variables including input costs, willingness to pay, end use, and the PTC.

Key inputs and assumptions:

Electrolysis projects that claimed the PTC are more likely to operate at full utilization after the PTC sunset due to fully depreciated capital assets compared to projects built post-PTC expiration.

For Figure 24, the cashflows for an electrolysis-based production project co-located with an offtaker demanding ~260 kt p.a. clean hydrogen was analyzed for a range of willingness to pay. Two scenarios were considered: existing hydrogen production projects built in 2023 that were no longer eligible for the PTC, and new hydrogen production projects built in 2035 that were not able to claim the PTC. For both categories, the free cashflows and IRRs were calculated at a series of willingness to pay values and LCOEs. The cutoff point for when existing projects built in 2023 were no longer profitable was set as the present value of the post-PTC (credit expiration) free cashflows. For new projects, the cutoff was set at a 7% IRR.

Excluding road transport, for both types of production, in the base case the model assumes the production project is co-located with an offtaker that requires constant offtake volume. The producer and offtaker are assumed to be connected via a short pipeline. For ammonia offtakers, electrolytic hydrogen was compressed to 200 bar for delivery, while for all other uses the produced hydrogen was compressed to 80 bar. For reformation-based hydrogen, no additional storage is assumed due to the firm nature of reformation production, while for electrolysis, sufficient storage for 50% of daily production for 1-day is assume to smooth intermittency and short-term variability. Storage is based on a salt cavern with a 200-mile pipeline between the cavern and the production site. Road transport assumes distribution from production facilities to refueling stations via gas-phase trucking and no additional storage costs for electrolysis due to greater offtake flexibility. Dispensing costs for road transport applications are subtracted from the overall willingness to pay for clean hydrogen to model production project economics using the willingness to pay for production.

The willingness to pay by end use was based on the midpoint of the willingness to pay range reported in the DOE National Hydrogen Strategy and Roadmap.[x] Maritime willingness to pay was based on the willingness to pay for biofuels and synfuels. Willingness to pay for power and natural gas blending was calculated assuming a ~$4/MMBtu long-term natural gas price. The exact willingness to pay values used are:

- Ammonia: $1.5/kg
- Refining: $1.0/kg
- Steel: $2.0/kg
- Methanol: $1.5/kg
- Road transport: $4.5/kg
- Maritime: $1.5/kg (based on ammonia and methanol willingness to pay)
- Natural gas blending: $0.5/kg
- Industrial heat: $1.0/kg
- Power (100% hydrogen combustion for high-capacity firm): $0.5/kg
- Power (fuel cell or hydrogen combustion for lower-capacity factor power): Not analyzed in this version of the Clean Hydrogen Liftoff report

A series of assumptions were made for both electrolysis and reformation-based hydrogen with CCS. For both types of projects, 10-year straight line depreciation was used, and 100% equity investments were assumed, in line with the financing of current projects. A 25-year asset lifetime and 15% tax rate were also assumed. For reformation-based hydrogen a 5-year development time was assumed while 2 years were assumed for electrolysis.

ATR and electrolyzer capex costs were derived using Methodology 3. In all cases, a 500,000 Nm3/h ATR facility with carbon capture was assumed, while the alkaline electrolyzer system size increased over time, consistent with Methodology 4. A ~2 MW (450 Nm^3/h) electrolyzer was assumed until 2025, then a ~18 MW (4000 Nm^3/h) electrolyzer until 2030, and finally a ~90 MW (20,000 Nm3/h) electrolyzer from 2030 onwards.

A 750 kt ammonia offtaker plant was assumed, while for road transportation 10 kt p.a. hydrogen demand was used, representing a few nearby refueling stations. An 800 MW combined cycle gas turbine (CCGT) plant representing ~260 kt p.a. hydrogen demand was assumed for power offtakers (100% hydrogen combustion for high-capacity firm power). Other offtakers were assumed to have the same hydrogen demand (~260 kt p.a.) as high-capacity firm power offtakers. Note that for reformation facilities, the hydrogen output is larger than the demand from a single ammonia or road transportation offtaker, so there is an implicit assumption that a reformation facility will service several nearby offtakers. For electrolysis, the same is true for road transportation applications – one facility will likely service a set of refueling stations. More detailed assumptions and sensitivity analyses are shown below in Figures 29-38.

Outputs:

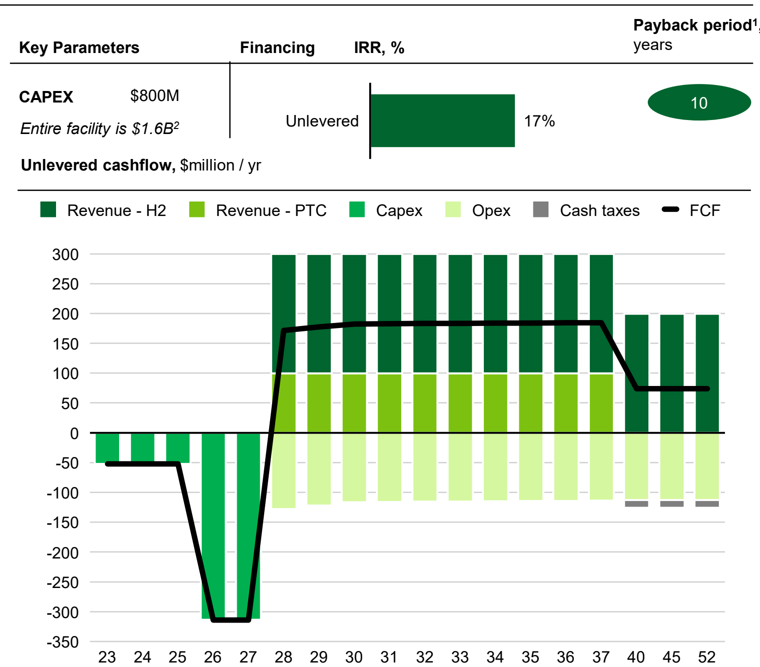
Ammonia

Inputs and key variables

ILLUSTRATIVE EXAMPLE

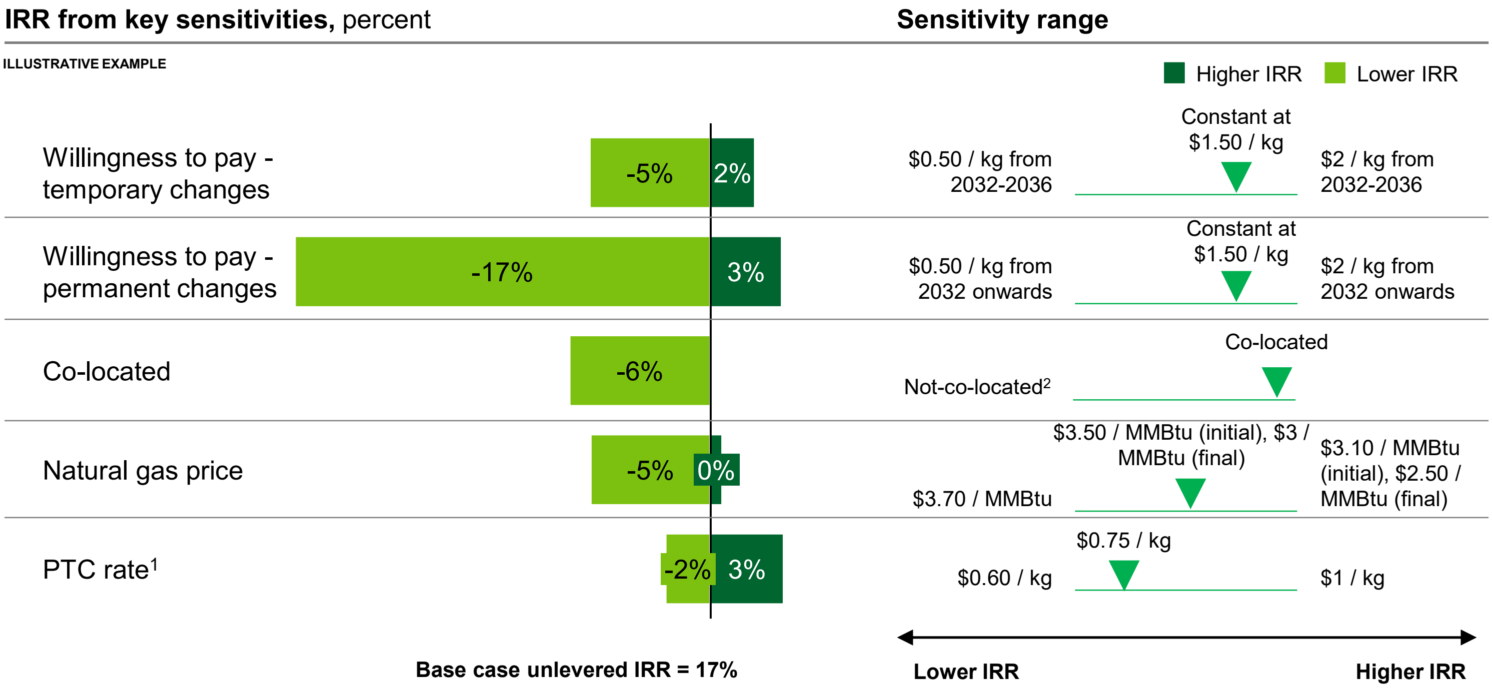
Category	Variable		Value
Revenues	H2 willingness to pay		$1.5/kg
	H2 PTC		$0.75/kg for 10 years
Costs	Levelized production cost		$1.2/kg (initial), $1.1/kg (final)
	CAPEX	Construction[3]	$1.05 billion (ATR) and $600 million (CCS) per 500,000 Nm^3/h capacity
	OPEX	Natural gas	$3.50 / MMBtu (initial), $3 / MMBtu (final)
		Carbon capture	$30 / tonne CO2
	Distribution and storage	Costs	$0.1/kg
		Assumptions	Pipeline to connect co-located producer and offtake
Financing and timelines	Financing	Debt / equity split	100% equity
		Tax rate	15%
		Depreciation	10 years, straight line
	Timelines	Development time	5 years
		Asset lifetime	25 years
H2 production facility	Production type		ATR + CCS
	Production offtake		~130 kt p.a.
	Ammonia offtake demand		750 kt ammonia p.a.
	Co-located		Yes
	Load factor		95%

Key outputs



1 Includes 5-year development time
2 Represents 500,000 Nm^3 / h facility since ATR facilities are not economical at small scale; additional offtakers would be required to match production volume
3 Includes equipment and installation
NOTE: All revenues and costs are based on current real dollars

Figure 29: Project economics of hydrogen production from ATR + CCS co-located with ammonia offtakers



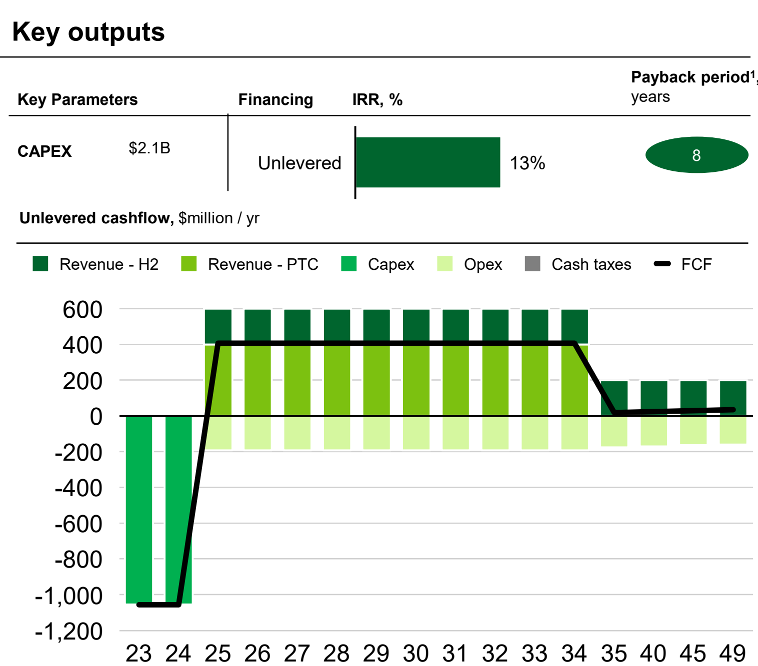
1 Corresponds to EIA reference, low oil price, and high oil price cases; Natural gas base case price linearly decreasing to $3 / MMBtu by 2030, then holding constant
2 Assumes gas-phase truck distribution over an average of 100 km

Figure 30: Sensitivities for project economics of hydrogen production from ATR + CCS co-located with ammonia offtakers

Inputs and key variables

ILLUSTRATIVE EXAMPLE

Category	Variable		Value
Revenues	H2 willingness to pay		$1.5/kg
	H2 PTC		$3/kg for 10 years
Costs	Levelized production cost		$2.1/kg (initial), $1.7/kg (final)
	CAPEX	Construction[2]	$1400/kW
	OPEX	Electricity	$1.1/kg (10 yr), $0.7/kg (final)
		Refurbishments	$0.1/kg
		Operations	< $0.1/kg
		Water	< $0.1/kg
	Distribution and storage	Costs[3]	$0.3/kg
		Assumptions	Pipeline to connect co-located producer and offtake, 50% H2 stored for 1 day (avg), rest compressed to 200 bar and transported
Financing and timelines	Financing	Debt / equity split	100% equity
		Tax rate	15%
		Depreciation	10 years, straight line
	Timelines	Development time	2 years
		Asset lifetime	25 years
H2 production facility	Production type		1.5 GW alkaline electrolyzer
	Production offtake		~130 kt p.a.
	Ammonia offtake demand		750 kt ammonia p.a.
	Co-located		Yes
	Capacity factor[4]		51% (initial), 55% (final)
	LCOE[4]		$23 / MWh (10 yr), $15 / MWh (final)

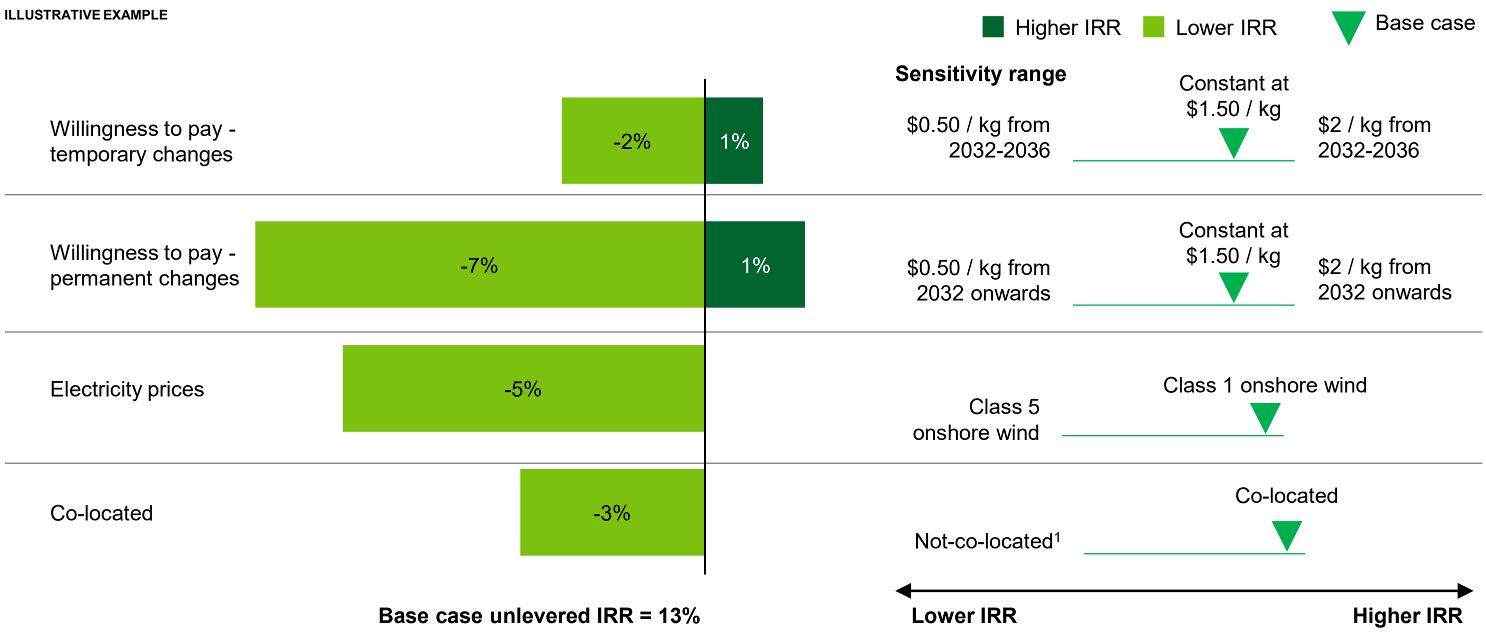


1 Includes 2-year development time
2 Includes both equipment and installation
3 Cost is normalized by full production volume, not by the amount stored / compressed. Levelized cost of storage is $0.1/kg based on an installed capex of $35/kg for salt cavern storage and $0.2/mile levelized cost for new 200-mile pipeline to connect production with salt cavern (includes compression to 200 bar)
4. Based on NREL Annual Technology Baseline Class 1 onshore wind
NOTE: All revenues and costs are based on current real dollars

Figure 31: Project economics of hydrogen production from alkaline electrolysis co-located with ammonia offtakers

IRR from key sensitivities, percent

Sensitivity range



1 Assumes gas-phase truck distribution over an average of 100 km

Figure 32: Sensitivities for project economics of hydrogen production from alkaline electrolysis co-located with ammonia offtakers

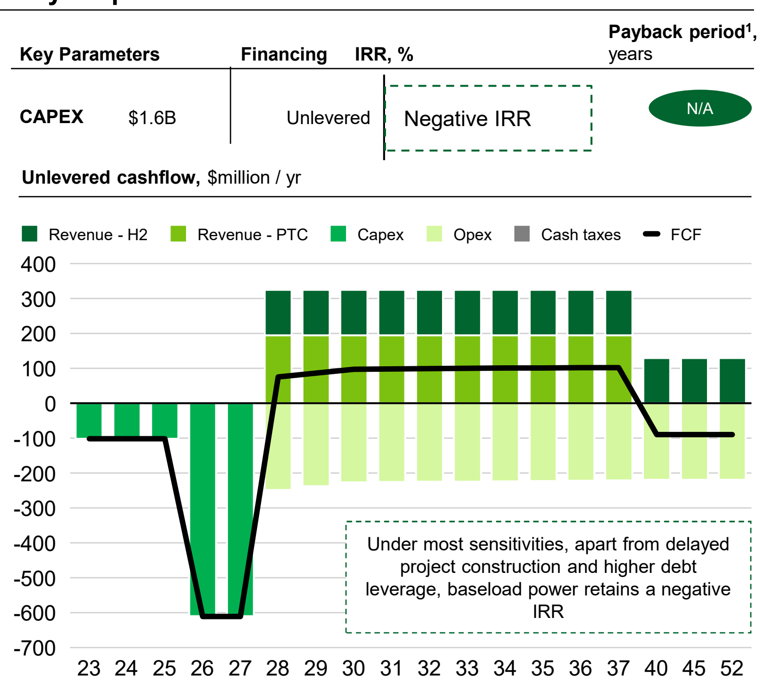
High-capactiy factor firm poiwer (100% hydrogen combustion)

Inputs and key variables

ILLUSTRATIVE EXAMPLE

Category	Variable		Value
Revenues	H2 willingness to pay		$0.5/kg
	H2 PTC		$0.75/kg for 10 years
Costs	Levelized production cost		$1.2/kg (initial), $1.1/kg (final)
	CAPEX	Construction[2]	$1.05 billion (ATR) and $600 million (CCS) per 500,000 Nm^3/h capacity
	OPEX	Natural gas	$3.50 / MMBtu (initial), $3 / MMBtu (final)
		Carbon capture	$30 / tonne CO2
	Distribution and storage	Costs	$0.1/kg
		Assumptions	Pipeline to connect co-located producer and offtake
Financing and timelines	Financing	Debt / equity split	100% equity
		Tax rate	15%
		Depreciation	10 years, straight line
	Timelines	Development time	5 years
		Asset lifetime	25 years
H2 production facility	Production type		ATR + CCS
	Production offtake		~260 kt p.a. (800 MW plant)
	Co-located		Yes
	Load factor		95%

Key outputs



1 Includes 5-year development time
2 Includes both equipment and installation
NOTE: All revenues and costs are based on current real dollars

Figure 33: Project economics of hydrogen production from ATR + CCS co-located with high-capacity firm power offtakers

Inputs and key variables

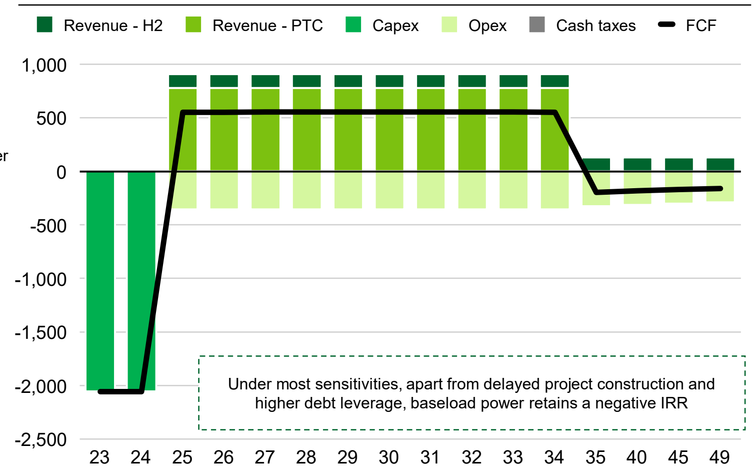
ILLUSTRATIVE EXAMPLE

Category	Variable		Value
Revenues	H2 willingness to pay		$0.5/kg
	H2 PTC		$3 / kg for 10 years
Costs	Levelized production cost		$2.1/kg (initial), $1.7/kg (final)
	OPEX	Electricity	$1.1/kg (10 yr), $0.7/kg (final)
	CAPEX	Construction[2]	$1400/kW
		Refurbishments	$0.1 / kg
		Operations	< $0.1/kg
		Water	< $0.1/kg
	Distribution and storage	Costs[3]	$0.3/kg
		Assumptions	Pipeline to connect co-located producer and offtake, 50% H2 stored for 1 day (avg), rest transported at pipeline pressure
Financing and timelines	Financing	Debt / equity split	100% equity
		Tax rate	15%
		Depreciation	10 years, straight line
	Timelines	Development time	2 years
		Asset lifetime	25 years
H2 production facility	Production type		3 GW alkaline electrolyzer
	Production offtake		~260 kt p.a. (800 MW plant)
	Co-located		Yes
	Capacity factor[4]		51% (initial), 55% (final)
	LCOE[4]		$23/MWh (10 yr), $15/MWh (final)

Key outputs

Key Parameters		Financing	IRR, %	Payback period[1], years
CAPEX	$4.1B	Unlevered	Negative IRR	N/A

Unlevered cashflow, $ million / yr



1 Includes 2-year development time
2 Includes both equipment and installation
3 Cost is normalized by full production volume, not by the amount stored / compressed. Levelized cost of storage is $0.1/kg based on an installed capex of $35/kg for salt cavern storage and $0.2/mile levelized cost for new 200-mile pipeline to connect production with salt cavern (includes compression to 200 bar)
4. Based on NREL Annual Technology Baseline Class 1 onshore wind
NOTE: All revenues and costs are based on current real dollars

Figure 34: Project economics of hydrogen production from alkaline electrolysis co-located with high-capacity firm power offtakers

Heavy-duty fuel trucks

Inputs and key variables

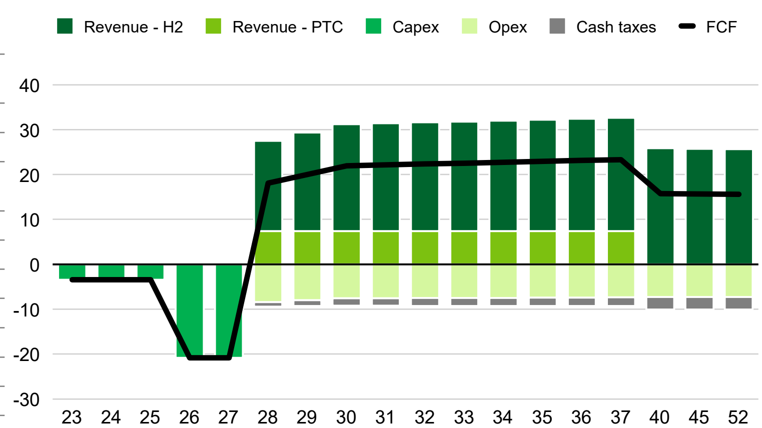
ILLUSTRATIVE EXAMPLE

Category	Variable		Value
Revenues	H2 willingness to pay		$4.5/kg, incl. dist. Costs; excess sold to refiners at $1/kg
	H2 PTC		$0.75/kg for 10 years
Costs	Levelized production cost		$1.2/kg (initial), $1.1/kg (final)
	CAPEX	Construction[3]	$1.05 billion (ATR) and $600 million (CCS) per 500,000 Nm^3/h capacity
	OPEX	Natural gas	$3.50 / MMBtu (initial), $3 / MMBtu (final)
		Carbon capture	$30 / tonne CO2
	Distribution and storage	Costs	$2.5/kg (initial), $1.9/kg (final)
		Assumptions	Assumes transport via GH2 trucking, no long-term storage costs
Financing and timelines	Financing	Debt / equity split	100% equity
		Tax rate	15%
		Depreciation	10 years, straight line
	Timelines	Development time	5 years
		Asset lifetime	25 years
H2 production facility	Production type		ATR + CCS
	Production offtake		~10 kt p.a.
	Co-located		Yes
	Load factor		95%

Key outputs

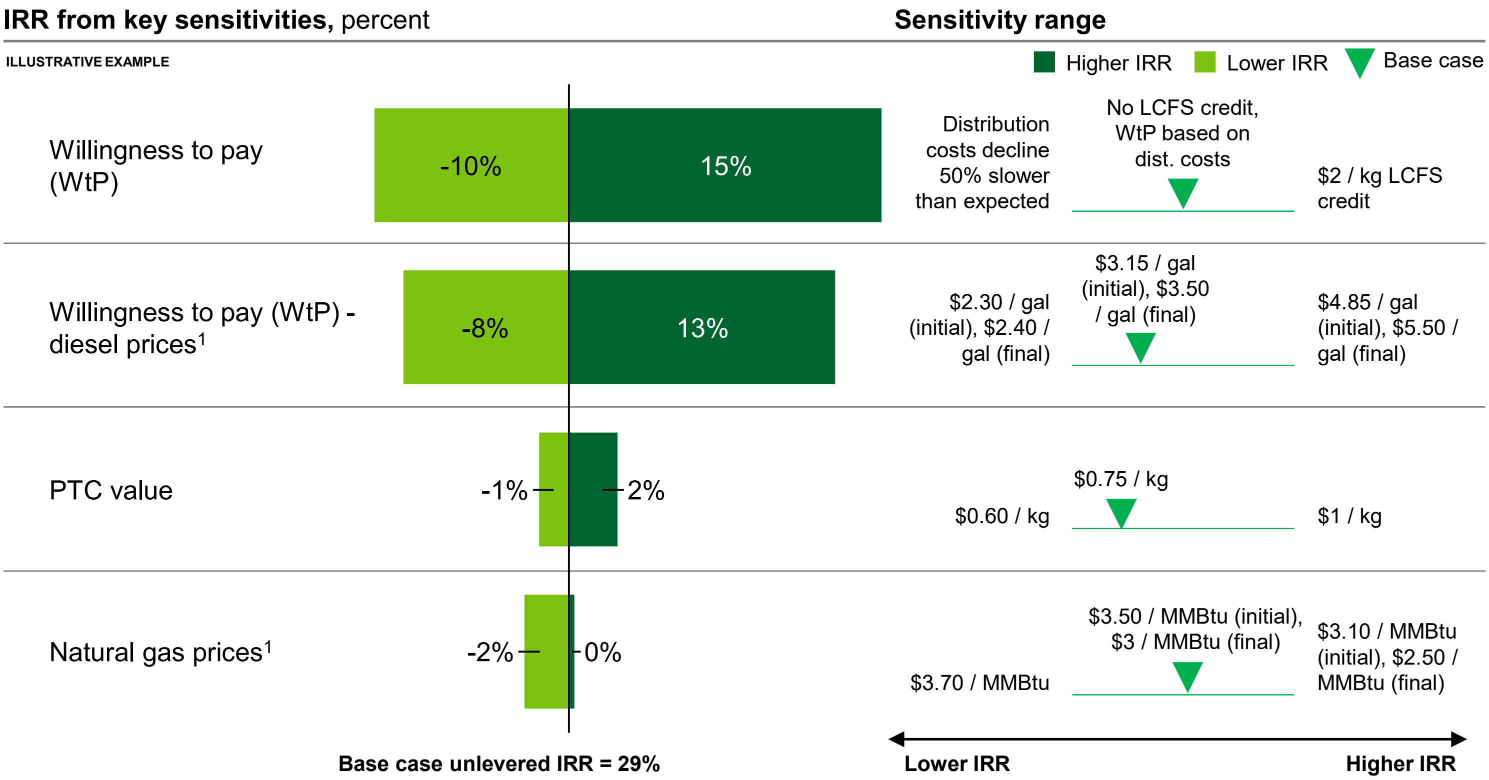
Key Parameters		Financing	IRR, %	Payback period[1], years
CAPEX	$50M	Unlevered	29%	8
Entire facility is $1.6B[2]				

Unlevered cashflow, $ million / yr



1 Includes 5-year development time
2 Represents 500,000 Nm^3 / h facility since ATR facilities are not economical at small scale; additional offtakers would be required to match production volume
3 Includes both equipment and installation
NOTE: All revenues and costs are based on current real dollars

Figure 35: Project economics of hydrogen production from ATR + CCS with fuel cell truck offtakers



1 Corresponds to EIA reference, low oil price, and high oil price cases; Natural gas base case price linearly decreasing to $3 / MMBtu by 2030, then holding constant

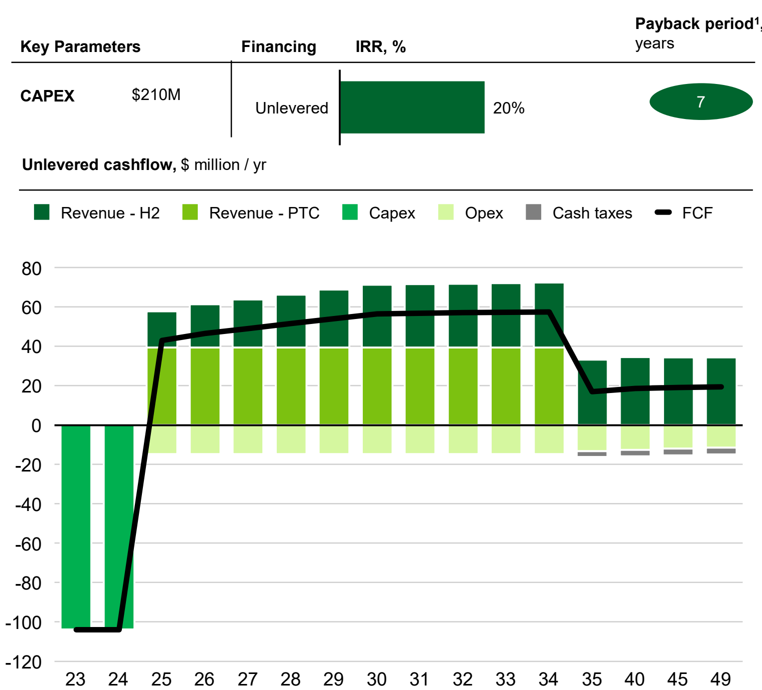
Figure 36: Sensitivities for project economics of hydrogen production with ATR + CCS for fuel cell truck offtakers

Inputs and key variables

ILLUSTRATIVE EXAMPLE

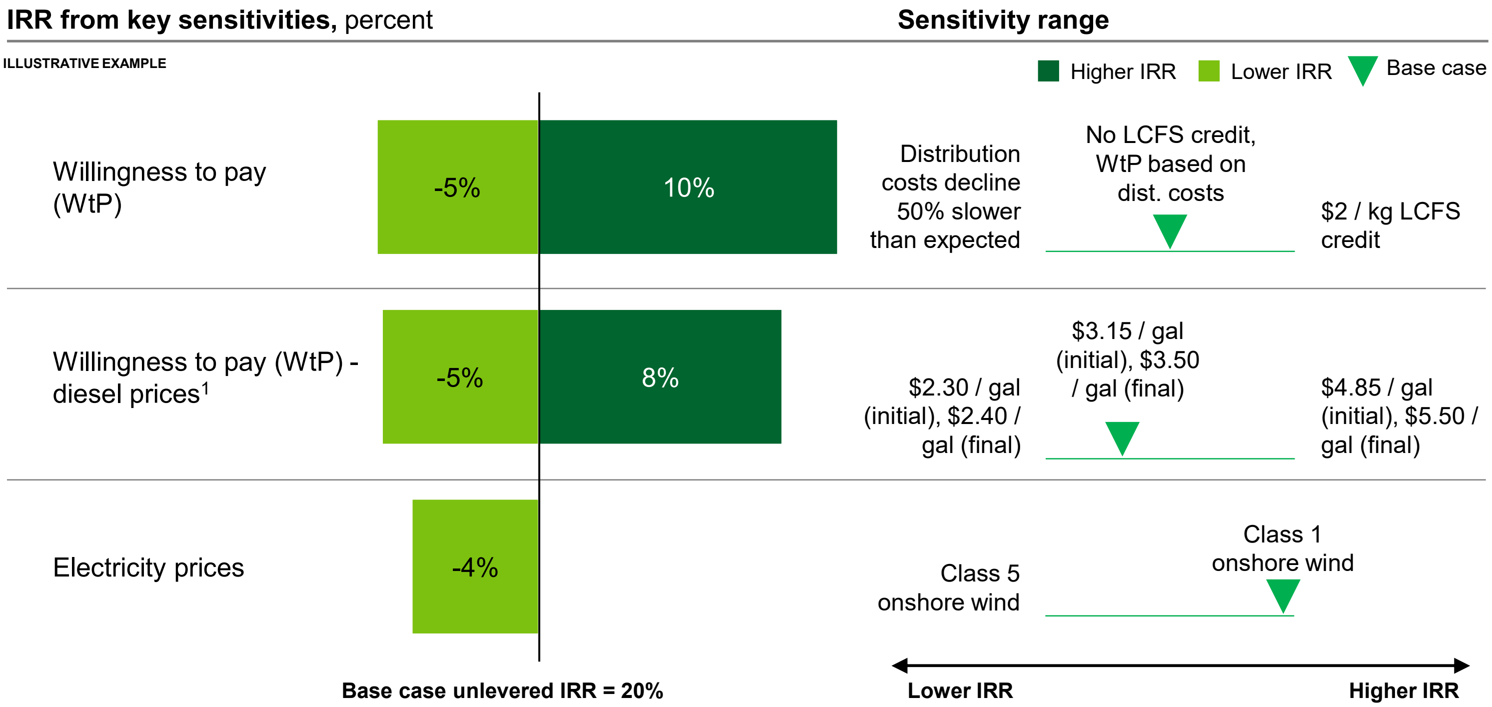
Category	Variable		Value
Revenues	H2 willingness to pay		$4.5/kg, incl. dist. costs; excess sold to refiners at $1 / kg
	H2 PTC		$3/kg for 10 years
Costs	Levelized production cost		$2.1/kg (initial), $1.7/kg (final)
	CAPEX	Construction[2]	$1400/kW
	OPEX	Electricity	$1.1/kg (10 yr), $0.7/kg (final)
		Refurbishments	$0.1/kg
		Operations	< $0.1/kg
		Water	< $0.1/kg
	Distribution and storage	Costs	$3.0 / kg (initial), $1.9 / kg (final)
		Assumptions	Assumes transport via GH2 trucking, no long-term storage costs
Financing and timelines	Financing	Debt / equity split	100% equity
		Tax rate	15%
		Depreciation	10 years, straight line
	Timelines	Development time	2 years
		Asset lifetime	25 years
H2 production facility	Production type		150 MW alkaline electrolyzer
	Production offtake		~10 kt p.a.
	Co-located[3]		Yes
	Load factor		51% (initial), 55% (final)
	LCOE[3]		$23 / MWh (10 yr), $15 / MWh (final)

Key outputs



1 Includes 2-year development time
2 Includes both equipment and installation
3 Based on NREL Annual Technology Baseline Class 1 onshore wind
NOTE: All revenues and costs are based on current real dollars

Figure 37: Project economics of hydrogen production with alkaline electrolysis for fuel cell truck offtakers



1. Corresponds to EIA reference, low oil price, and high oil price cases

Figure 38: Sensitivities for project economics of hydrogen production with alkaline electrolysis for fuel cell truck offtakers

Considerations and limitations of approach:

There are also a series of implicit assumptions used in developing the cashflow model, which are outlined below.

Supply chain/workforce

- Electrolyzer/labor availability: There is sufficient electrolyzer manufacturing capacity and skilled labor to build >1 GW electrolyzer facilities starting in 2023 (i.e., similar to the Hydrogen City project)

Supporting infrastructure

- CCS infrastructure: CCS is technologically mature and can be deployed at scale
- Pipelines: a pipeline can be built connecting the production project with a salt cavern
- Wind power: another developer is willing to build a >1GW wind farm to power electrolysis facilities at a competitive LCOE, in line with the NREL Annual Technology Baseline
- Fuel cell trucks: refueling infrastructure is built out as expected with declining capex costs over time
- Seasonal storage: Electrolysis projects can avoid paying for long-term seasonal storage by acquiring hydrogen from other producers to meet contracts
- Capex and electricity prices: Electrolyzer capex and renewable electricity prices continue to decline in line with industry forecasts

Project specific

- Geographic constraints: projects have nearby carbon sequestration sites, salt cavern storage, and a large-scale wind farm
- Wages: projects can meet fair wage and apprenticeship requirements to obtain the full PTC

End user

- Contracting: Buyer is willing to sign a long-term offtake contract at the midpoint of the willingness to pay for their end use
- Switching costs: costs for end users to switch to clean hydrogen are small enough to not significantly hinder implementation of clean hydrogen

Financing, policy, and broader market

- Financing: there is sufficient equity financing available for >$1B projects
- Policy: H2 PTCs remain in effect in their current form for projects that begin construction prior to 2033

Table of Figures

References

i. The first Energy Earthshot—Hydrogen Shot—seeks to reduce the cost of clean hydrogen by 80% to $1 per 1 kilogram in 1 decade ("1 1 1"). Source: Energy.gov. (2021). *Hydrogen Shot*. Retrieved from https://www.energy.gov/eere/fuelcells/hydrogen-shot

ii. McKinsey Energy Insights Global Energy Perspective. (2021)

iii. U.S. Department of Energy. (2022). *DOE National Clean Hydrogen Strategy and Roadmap*. Retrieved from https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf

iv. S&P Global Community Insights. (2021). *Hydrogen Market Outlook, Supply & Demand, Forecast and Analysis*. Retrieved from https://www.spglobal.com/commodityinsights/en/ci/products/hydrogen-chemical-economics-handbook.html

v. The U.S. forecast ~29GW of solar and wind capacity additions in 2022. Source: US Energy Information Administration. (2022). *Solar power will account for nearly half of new U.S. electric generating capacity in 2022*. Retrieved from https://www.eia.gov/todayinenergy/detail.php?id=50818

vi. Warwick, N., Griffiths, P., Keeble, J., Archibald, A., Pyle, J., Shine, K., (2022). *Atmospheric Implications of Increased Hydrogen Use*. Retrieved from https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1067144/atmospheric-implications-of-increased-hydrogen-use.pdf

vii. National Energy Technology Laboratory. (2022). *Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies*. Retrieved from https://netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf

viii. Water electrolysis also requires the availability of deionized water, although water is unlikely to be a significant constraint on electrolyzer deployment. Water electrolysis facilities use 3–4 gallons/kg H2, while incumbent technologies such as SMR and coal gasification use ~3 and ~8 gallons/kg H2, respectively. Based on these values, 10 MMT hydrogen produced from water electrolysis would require 29 billion gallons of water. While this quantity could cause water stress if concentrated in one arid region, it represents <0.03% of the estimated annual freshwater withdrawal in the United States. In addition, this use will be partially offset by forgone water consumption for energy that is being displaced by hydrogen. Source: Connelly, E., Penev, M., Milbrandt, A., Roberts, B., Gilroy, N., Melaina, M. (2020), *Resource Assessment for Hydrogen Production*. Retrieved from https://www.nrel.gov/docs/fy20osti/77198.pdf

ix. 2021 data from Institute for Energy Innovation at Carnegie Mellon University. (2022). Power Sector Carbon Index. Retrieved from https://emissionsindex.org/

x. European Hydrogen Backbone. (2022). A European Hydrogen Infrastructure Vision Covering 28 Countries. Retrieved from https://ehb.eu/files/downloads/ehb-report-220428-17h00-interactive-1.pdf

xi. California Public Utilities Commission. (2022). *CPUC Issues Independent Study on Injecting Hydrogen Into Natural Gas Systems*. Retrieved from https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-issues-independent-study-on-injecting-hydrogen-into-natural-gas-systems

xii. US DOE Hydrogen and Fuel Cell Technologies Office. (2022). *DOE Technical Targets for Hydrogen Delivery*. Retrieved from https://www.energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-delivery

xiii. Ammonia emits around 2.4 t CO2 per ton of production. Source: International Energy Agency. (2022). *Ammonia Technology Roadmap.* Retrieved from https://www.iea.org/reports/ammonia-technology-roadmap/executive-summary

xiv. International Energy Agency. (2022). *Ammonia Technology Roadmap.* Retrieved from https://www.iea.org/reports/ammonia-technology-roadmap/executive-summary

xv. Private companies operate ~2000 miles of ammonia pipeline in the Gulf Coast and Midwest transporting 1.5 million tons of anhydrous ammonia per year. Source: NUSTAR ENERGY L.P. (2018). *Form 10-K*. Retrieved from https://www.sec.gov/Archives/edgar/data/1110805/000111080519000049/ns201810-k.htm

xvi. More than 15 million MMT are exported annually, and the U.S. has more than 10,000 ammonia storage sites. Source: The Royal Society. (2020). *Ammonia: zero-carbon fertiliser, fuel and energy store.* Retrieved from https://royalsociety.org/-/media/policy/projects/green-ammonia/green-ammonia-policy-briefing.pdf.; International Energy Agency. (2022). *Ammonia Technology Roadmap.* Retrieved from https://www.iea.org/reports/ammonia-technology-roadmap/executive-summary

xvii. Use of ammonia as a hydrogen carrier for export will depend on its performance in comparison to liquid hydrogen and other hydrogen carriers, including methanol and liquid organic hydrogen carriers (LOHCs). Currently, ammonia conversion is energy intensive; if ammonia is used directly in end markets, the energy efficiency to convert hydrogen to ammonia is 33-67%[1], which drops to 10-40%[2] if the ammonia is reconverted to hydrogen.[i] In contrast, liquefaction efficiencies are typically 55-70%[3], although liquid hydrogen is more challenging to store due to cryogenic temperature requirements. [1] 11-22 kWh kgH2-1 required for Haber-Bosch production of ammonia [2] Additional ~8 kWh kgH2-1 required for reconversion of ammonia back to hydrogen [3] 10-15 kWh kgLH2-1 [i]. Source: Royal Society of Chemistry. (2022). *Hydrogen liquefaction: a review of the fundamental physics, engineering practice and future opportunities.* Retrieved from https://pubs.rsc.org/en/content/articlepdf/2022/ee/d2ee00099g

xviii. International Renewable Energy Agency. (2021). *Innovation Outlook, Renewable Methanol.* Retrieved from: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jan/IRENA_Innovation_Renewable_Methanol_2021.pdf?rev=ca7ec52e824041e8b20407ab2e6c7341

xix. U.S. Department of Energy. (2022). *U.S. DOE Industrial Decarbonization Roadmap.* Retrieved from: https://www.energy.gov/sites/default/files/2022-09/Industrial%20Decarbonization%20Roadmap.pdf.

xx. U.S. Department of Energy. (2023). *The U.S. National Blueprint for Transportation Decarbonization.* Retrieved from: https://www.energy.gov/sites/default/files/2023-01/the-us-national-blueprint-for-transportation-decarbonization.pdf

xxi. Assuming $50/tonne CO_2 capture cost and ~2 kg CO_2e/kg ammonia based on Liu, Xinyu, Amgad Elgowainy, and Michael Wang. "Life cycle energy use and greenhouse gas emissions of ammonia production from renewable resources and industrial by-products." *Green Chemistry* 22.17 (2020): 5751-5761.; Baltrusaitis, Jonas. "Sustainable ammonia production." *ACS Sustainable Chemistry & Engineering* 5.11 (2017): 9527-9527.

xxii. Assumes 25% base capex to retrofit facility and $1000/kW base capex for initial natural gas plant. Sources: NREL 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.

xxiii. United States Department of State and the United States Executive Office of the President. (2021). *The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050.* Retrieved from: https://www.whitehouse.gov/wp-content/uploads/2021/10/US-Long-Term-Strategy.pdf

xxiv. Hunter, C. A., Penev, M. M., Reznicek, E. P., Eichman, J., Rustagi, N., & Baldwin, S. F. (2021). Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high-variable renewable energy grids. *Joule*, *5*(8), 2077-2101.

xxv. Earth Justice. (2021). *Reclaiming hydrogen for a renewable future: distinguishing oil & gas industry spin from zero-emission solutions.* Retrieved from: https://earthjustice.org/sites/default/files/files/hydrogen_earthjustice_2021.pdf

xxvi. Hydrogen Council. (2020). *Path to hydrogen competitiveness: a cost perspective.* Retrieved from https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

xxx. Argonne National Laboratory. (2022). *Hydrogen Delivery Scenario Analysis Model.* Retrieved from https://hdsam.es.anl.gov/index.php?content=hdsam

xxxi. Air Liquide inaugurates in the U.S. its largest liquid hydrogen production facility in the world. Source: Company website. Retrieved from: https://usa.airliquide.com/air-liquide-inaugurates-us-its-largest-liquid-hydrogen-production-facility-world

xxxii. Hyosung, Linde partner to construct liquid hydrogen plant in South Korea. Source: NS Energy. Retrieved from: https://www.nsenergybusiness.com/news/hyosung-linde-liquid-hydrogen/

xxxiii. Ahluwalia, R. K., et al. "System level analysis of hydrogen storage options." *Proceedings of the 2008 US DOE Hydrogen Program Annual Merit Review* (2010).

xxxiv. International Energy Agency and IEA and Organization for Economic Cooperation and Development. (2018). *The Future of Petrochemicals: Towards more sustainable plastics and fertilizers*. Retrieved from https://iea.blob.core.windows.net/assets/bee4ef3a-8876-4566-98cf-7a130c013805/The_Future_of_Petrochemicals.pdf

xxxv. U.S. Department of Energy. (2022). *SAF Grand Challenge Roadmap: Flight Plan for Sustainable Aviation Fuel.* Retrieved from https://www.energy.gov/sites/default/files/2022-09/beto-saf-gc-roadmap-report-sept-2022.pdf

xxxvi. Smith, T., Baresic, D., Fahnestock, J., Galbraith, C., Perico, C. V., & Rojon, I. (2021). A Strategy for the Transition to Zero-Emission Shipping an Analysis of Transition Pathways. *Scenarios, and Levers for Change (University Maritime Advisory Services (UMAS))*.

xxxvii. Hydrogen Council. (2022). *Hydrogen Insights 2022*. Retrieved from https://hydrogencouncil.com/wp-content/uploads/2022/09/Hydrogen-Insights-2022-2.pdf

xxxviii. Badgett, A., et al. "Water Electrolyzers and Fuel Cells Supply Chain: Supply Chain Deep Dive Assessment." *Report to the U.S. Department of Energy* (2022).

xxxix. Nel Hydrogen. (2022) *Introduction to Liquid Alkaline Electrolysis.* Retrieved from https://www.energy.gov/sites/default/files/2022-02/2-Intro-Liquid%20Alkaline%20Workshop.pdf

xl. U.S. Geological Survey. (2022). *Mineral Commodity Summaries 2022.* Retrieved from https://pubs.usgs.gov/periodicals/mcs2022/mcs2022-platinum.pdf

xli. IMPLAN. (2022). *How IMPLAN Works.* Retrieved from https://support.implan.com/hc/en-us/articles/360038285254-How-IMPLAN-Works

xlii. Hydrogen Council. (2022). *Global Hydrogen Flows: Hydrogen trade as a key enabler for efficient decarbonization.* Retrieved from https://hydrogencouncil.com/wp-content/uploads/2022/10/Global-Hydrogen-Flows.pdf

xliii. Hydrogen Council. (2022). *Hydrogen for Net-Zero: A critical cost-competitive energy vector.* Retrieved from https://hydrogencouncil.com/wp-content/uploads/2021/11/Hydrogen-for-Net-Zero.pdf

xliv. National Renewable Energy Laboratory. (2022). *Scenario Evaluation and Regionalization Analysis Model.* Retrieved from https://www.nrel.gov/hydrogen/sera-model.html

U.S. DEPARTMENT OF
ENERGY