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CLEANING UP GRAY HYDROGEN:

Directing Low-Emissions Hydrogen Use to Fertilizer Production and Refining

Emily Kent and Anna Dixon

Environmental Defense Fund

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Emily Kent[a], Anna Dixon[b]

a David Gardiner & Associates
b David Gardiner & Associates

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Executive Summary

Low-emissions hydrogen has an important role to play in decarbonization, but it also brings key challenges: it is energy intensive to produce, costly (even with existing policy support), and prone to leakage, all of which impact hydrogen's potential as a climate solution. It is thus important to use limited supplies of low-emissions hydrogen wisely—in other words, in sectors where it is technically feasible and will offer the greatest climate benefit.

The United States (U.S.) currently produces about 10 million metric tons (MMT) of hydrogen per year through conventional processes that result in emissions of about 100 MMT carbon dioxide equivalent (CO_2e) per year.[1] Today, 95% of hydrogen in the U.S. is produced from natural gas, which results in approximately 8 to 12 kilograms (kg) of CO_2e per kg of hydrogen. Hydrogen itself can also indirectly contribute to atmospheric warming, posing additional challenges to expanding a system for a molecule that leaks easily and requiring that infrastructure be intentionally developed and maintained to minimize hydrogen leaks. Low-emissions hydrogen production pathways are demonstrated and ready for deployment, particularly including electrolysis paired with clean electricity and natural gas reforming with carbon capture and sequestration (CCS) and stringent upstream methane controls to minimize methane leakage. However, potential end-uses of hydrogen are in various stages of technology-readiness and result in vastly different climate benefits. **Incumbent industries that already require hydrogen—namely, ammonia production for fertilizers and refining of fuels and chemicals—represent promising applications for low-emissions hydrogen deployment.**

[1] This is calculated using a generally accepted emissions intensity of approximately 10 kilograms of CO_2e per kilogram of hydrogen produced from natural gas steam methane reforming. It is worth noting that the emissions intensities used in this paper utilize a 100-year Global Warming Potential (GWP); however, a 20-year GWP would more accurately reflect the significant near-term warming potential of methane in hydrogen production.

Through literature reviews, expert interviews, and policy analysis, this report explores the potential for low-emissions hydrogen to be used for decarbonizing these two industries. In particular, it conducts a deep-dive into the emissions opportunities and challenges in the ammonia fertilizer and refining sectors and finds significant barriers for uptake of low-emissions hydrogen in these incumbent industries. Finally, it proposes specifically targeted policy solutions to support effective deployment of low-emissions hydrogen to these particular sectors which have high emissions reduction potential.

Ammonia production is a major source of domestic emissions, accounting for 46 MMT of CO_2 in the U.S. in 2021, with the majority of ammonia's lifecycle emissions stemming from production of hydrogen—its key feedstock. The U.S. produces 17 MMT of ammonia annually, 88% of which is used for fertilizer. **Replacing all of the conventional high-emitting hydrogen production used to produce ammonia in the U.S. with low-emissions hydrogen could reduce emissions in the sector by up to 39 MMT CO_2 every year.**

Production in the U.S. is geographically concentrated in the Gulf Coast. Nationwide production is dominated by three companies—CF Industries, Nutrien, and Koch Industries—which together account for more than half of total domestic ammonia output. The global ammonia market is highly interconnected and volatile, with prices driven by supply and demand dynamics, natural gas costs, and geopolitical events. Most ammonia used for fertilizer production is traded with spot pricing or procured with short-term agreements.

Due to the ammonia sector's low profit margins (particularly taking into account low willingness to pay for green premiums by farmers purchasing fertilizer), decarbonization in the short term may rely more heavily on hydrogen produced from natural gas with high rates of CCS and very low upstream methane leak rates, rather than electrolytic hydrogen. Similarly, in the short term, most clean ammonia production is likely to serve existing fertilizer markets and new international demand—particularly in regions like South Korea and Japan—potentially shaping U.S. production methods and influencing the pace of global clean ammonia adoption.

The refining sector produces approximately 198 MMT of CO_2e annually, making up about 3% of U.S. emissions. Refineries convert heavy crude oil into finished petroleum products, relying heavily on hydrogen during this process for various types of hydrotreating and hydroprocessing of crude oil. Of the nearly 200 MMT of CO_2e, approximately 9% of the sector's emissions—or about 18 MMT—come from the on-site production of hydrogen. The refining sector, like ammonia, operates in a volatile global commodity market where crude oil prices drive refined product costs, and U.S. refineries—concentrated in the Gulf Coast, Midwest, and California—

source hydrogen either from merchant suppliers or on-site production, with increasing reliance on merchant suppliers in recent years. Estimates for on-site versus merchant supply of hydrogen in the refining sector range over time but averaged approximately 67% merchant supply and 33% on-site production during the 2013 to 2022 period. The refining sector is also dominated by a handful of large companies, with Marathon Petroleum, Valero Energy, Phillips 66, PBF Energy, and Chevron each refining over 1 million barrels of crude oil in the U.S. daily.

Domestic refineries are turning to carbon capture to decarbonize their hydrogen production, with large, planned projects including ExxonMobil's Baytown facility and the Gulf Coast Hydrogen Hub. Some international projects, including Shell's REFHYNE project and Total Energies' partnerships, are using electrolytic hydrogen for refining decarbonization.

Replacing the current hydrogen used in refineries (from both merchant and on-site production) with low-emissions hydrogen could reduce emissions by up to 55 MMT CO_2e per year. Combined with the ammonia sector, replacing conventional hydrogen with low-emissions hydrogen in these two incumbent uses could reduce U.S. emissions by up to 94 MMT CO_2e, or about 6 percent of U.S. industrial sector greenhouse gas (GHG) emissions and 1.5 percent of total U.S. GHG emissions.[2] Globally, hydrogen production (the vast majority of which is for incumbent uses) resulted in 920 MMT CO_2e in 2023, which is on par with the emissions from the global aviation industry.[3]

Numerous policy and market solutions can be leveraged to direct low-emissions hydrogen supply to the ammonia and refining industries. While more deeply discussed in the Policy section of this report, these include:

- Targeting financial instruments (e.g., tax credits, contracts for differences, low- and no-interest loans, and grants) to these specific sectors, and limiting policy support for sectors with minimal climate benefit.
- Establishing buyers' alliances, book and claim systems, and distributed business models to better connect supply and demand for low-emissions hydrogen and allow cost-sharing of the green premium along the entire value chain.
- Instituting product standards based on carbon intensity, low-carbon fuel standards, and statewide emissions caps or standards to better align private sector incentives with decarbonization needs.

[2] U.S. Environmental Protection Agency (EPA), "Industry Sector Emissions", last accessed April 29, 2025.
[3] International Energy Agency (IEA), "Global Hydrogen Review 2024", October 2024. For aviation emissions data, see IEA, "Aviation".

These solutions could be relevant at the state or federal jurisdictions in the U.S., depending on political viability, and many of them can be implemented via the private sector without requiring government involvement. Regardless of solution, many of these require rigorous GHG lifecycle accounting and verification. The buildout of a low-emissions hydrogen system to support decarbonization is also entirely dependent on the drastic minimization of methane leaks at the ammonia manufacturing plants and in the upstream natural gas supply chain, the development of CCS infrastructure built with safety and environmental integrity in mind, and the expansion of clean electricity and the U.S. transmission network. To maximize overall climate and economic benefits, supply of low-emissions hydrogen should be considered for use in the fertilizer and refining sectors to replace conventional hydrogen.

Introduction

Hydrogen has an important role to play in decarbonization, but it also brings key challenges. Even with existing subsidies, it can be very expensive to make (especially in its lowest GHG-emissions forms), transport, and store hydrogen. Equally as important, it is energy intensive to produce and can also leak easily—factors that are highly relevant in assessing whether hydrogen can be an effective climate solution.

For example, hydrogen itself has a global warming potential (GWP) of approximately 12 over a 100-year period and approximately 35-40 over a 20-year period.[4] For comparison, methane (one of the most potent short-lived climate pollutants) has a 100-year GWP of approximately 27-30 and a 20-year GWP of 78-83.[5] If hydrogen emissions (i.e., leaks, vents, or purges) are not carefully managed and minimized, the climate benefits from using otherwise low-emissions hydrogen can decrease.

Therefore, it is important to use limited supplies of low-emissions hydrogen wisely—directing it to the sectors where it has the most potential to reduce GHG emissions and where those end-uses do not currently have other easy, cost-effective decarbonization options. As the Section 45V clean hydrogen production tax credit helps address the cost barrier to widespread production of low-emissions hydrogen, policies are needed to direct deployment of this hydrogen to sectors where it will have the greatest climate impact. Hard-to-abate sectors suitable for low-emissions hydrogen use include existing uses of unabated fossil-based hydrogen—such as in refineries and

[4] Environmental Defense Fund (EDF), "Hydrogen Could Have Much Bigger Climate Impact Than Most Estimates, Study Shows". Specific data comes from: Environ. Sci. Technol. 2024, 58, 12, 5299–5309.
[5] IPCC, Sixth Assessment Report, Chapter 7, Table 7.15: "Emissions metrics for selected species: global warming potential (GWP), global temperature-change potential (GTP)".

in ammonia production, which together represent nearly 90% of today's hydrogen market.[6] Low-emissions hydrogen may also be of high climate value in sectors such as greenfield steel production and in the production of marine shipping and aviation fuel.[7]

This report will briefly introduce existing hydrogen production methods and decarbonization options, as well as GHG abatement potential for use of low-emissions hydrogen in incumbent industries. It will then focus on the two of these sectors that already use hydrogen today—ammonia production for use as fertilizer and hydrogen use in processing and treating fuels at refineries—and will outline U.S. market dynamics and decarbonization pathways for each sector. These sector discussions will be followed by a discussion of barriers (which outlines costs, timelines, and infrastructure needs) and a policy discussion with proposed solutions for addressing sectoral challenges and directing limited low-emissions hydrogen supply to these high-value uses.

Finally, as will be discussed later in the Introduction, when "low-emissions hydrogen" is used throughout this paper, it is intended to refer to both electrolytic and fossil-based hydrogen production pathways that drastically minimize their GHG emissions intensity. Additionally, this paper is focused on the GHG emissions and climate impact of hydrogen and thus does not address other non-GHG emissions like hazardous air pollutants that can be associated with hydrogen production and/or use.

Current Hydrogen Production Methods

The U.S. currently produces approximately 10 MMT of hydrogen annually, generating around 100 MMT of CO_2e per year.[8] Natural gas is used in 95% of U.S. hydrogen production today.[9] There are two primary production pathways for producing hydrogen from natural gas: steam methane reforming (SMR) and autothermal reforming (ATR). These production pathways emit between 8 and 12 kg of CO_2e per kg of hydrogen.[10]

SMR is the more common hydrogen production method—it is used for almost all commercial production in the U.S., including for refineries and industrial processes.[11] The first step of this process occurs in the primary reformer, where high-temperature steam (700°C–1,000°C) reacts with methane—from natural gas—under pressures ranging from 3 to 25 bar in the presence of a

[6] U.S. Energy Information Administration (EIA), "U.S. refiners and chemical manufacturers lead hydrogen production and consumption," Apr. 8, 2024.
[7] Johnson, N., Liebreich, M., Kammen, D.M. *et al.* Realistic roles for hydrogen in the future energy transition. *Nat. Rev. Clean Technol.* (2025). https://doi.org/10.1038/s44359-025-00050-4.
[8] U.S. Department of Energy (DOE), "U.S. National Clean Hydrogen Strategy and Roadmap," pg. 14, 2021.
[9] U.S. DOE, "Hydrogen Production: Natural Gas Reforming," last accessed Feb. 2025.
[10] RMI, "Hydrogen's Decarbonization Impact for Industry," pg. 6, Jan. 2020.
[11] U.S. EIA, "Hydrogen Explained: Production of Hydrogen," last acc. Feb. 2025.

catalyst. This reaction produces hydrogen, carbon monoxide, and a relatively small amount of carbon dioxide (CO_2). The carbon monoxide further reacts with steam in a water-gas shift (WGS) reaction to produce additional hydrogen, CO_2, and heat. SMR + WGS together is an overall endothermic process, requiring continuous heat input to sustain the reaction.[12] A third of the natural gas fed into a steam reformer is used as a fuel for the process (rather than the feedstock), generating flue gas CO_2.[13]

ATR is a similar process, but it requires less energy overall compared to SMR. ATR introduces oxygen into the reaction to produce heat, reducing the need for steam compared to SMR.[14] Additionally, a portion of the natural gas feedstock in ATR is combusted to further heat the process gas.[15] The CO_2 produced through ATR is in a more concentrated form than SMR, which allows higher rates of carbon capture to be more feasible on ATR facilities.

Existing Hydrogen Decarbonization Pathways

Two technologies currently exist—and are being deployed—that produce hydrogen with reduced GHG emissions. Natural gas-derived hydrogen ('gray' hydrogen) can be fully replaced with hydrogen produced from electrolysis and powered by clean electricity ('green' or 'pink' hydrogen if renewable or nuclear energy is used, respectively). GHG emissions can also be reduced from fossil-based hydrogen production (SMR and ATR) by coupling the process with carbon capture and storage ('blue' hydrogen) and minimizing methane leaks in the upstream natural gas supply chain. When natural gas is used on-site, research has found that ammonia manufacturing plants also have methane emissions from natural gas loss, which must be minimized to decarbonize the full value chain of the hydrogen.[16]

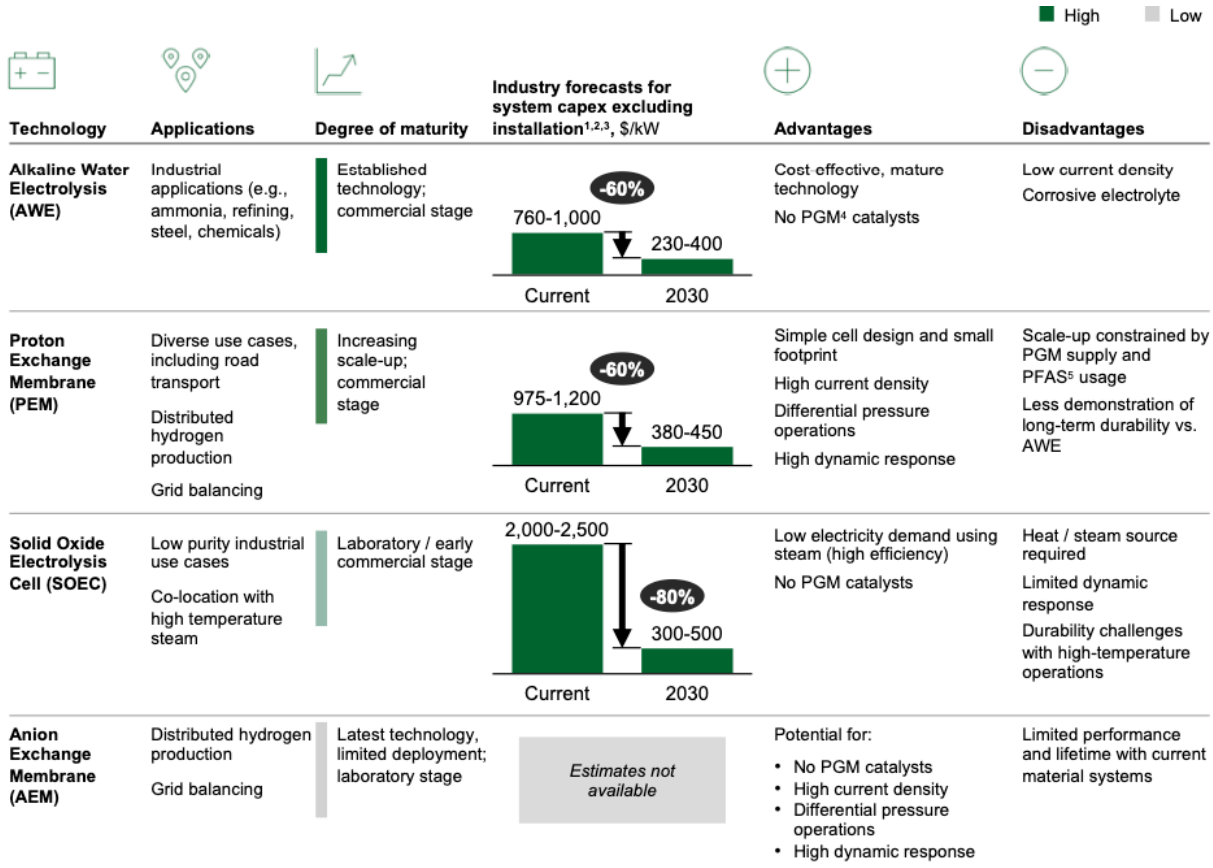
Electrolytic hydrogen is produced by splitting water into hydrogen and oxygen with an electrolyzer powered by electricity. To be a truly zero- or low-emissions hydrogen production process, the electrolyzer must be powered by additional renewable energy—clean electricity not currently used by other sectors or facilities. There are four electrolyzer technologies at various stages of maturity: alkaline water electrolysis (AWE), proton exchange membrane (PEM), solid oxide electrolysis (SOE), and anion exchange membrane (AEM). AWE is the most established technology and PEM electrolyzers are increasingly scaling up. PEM technologies feature a

[12] U.S. DOE, "Hydrogen Production: Natural Gas Reforming," last acc. Dec. 2024.
[13] U.S. DOE, "Hydrogen Production: Natural Gas Reforming," last acc. Dec. 2024.
[14] ICF, "Comparing The Costs Of Industrial Hydrogen Technologies," Nov. 30, 2023.
[15] U.S. National Energy Technology Laboratory (NETL), "Technologies for Hydrogen Production," last accessed Dec. 2024.
[16] Xiaochi Zhou, Fletcher H. Passow, Joseph Rudek, Joseph C. von Fisher, Steven P. Hamburg, John D. Albertson; Estimation of methane emissions from the U.S. ammonia fertilizer industry using a mobile sensing approach. *Elementa: Science of the Anthropocene* 1 January 2019; 7 19. doi: https://doi.org/10.1525/elementa.358

fluoropolymer-containing membrane, which are produced using per- and polyfluoroalkyl substances (PFAS). PEM and AEM also use PFAS in their sealing and coating materials and gaskets. SOE and AEM electrolyzers are still in the laboratory and early commercial stage.[17]

FIGURE 1

Electrolyzer Technologies [18]



'Blue' hydrogen can reduce GHG emissions at multiple key points in the hydrogen production system. The largest portion of emissions from 'gray' hydrogen comes from CO_2 emitted through the SMR or ATR process; thus, new or retrofitted facilities that use natural gas SMR or ATR systems must install carbon capture equipment capable of very high rates of carbon capture. The second largest portion of 'gray' hydrogen GHG emissions comes from methane, particularly in the upstream natural gas supply chain, though also released at the hydrogen or ammonia plant itself, as previously described. Methane's potency as a GHG means that upstream leak rates are a considerable contributor to the carbon intensity of hydrogen production. Recent research has

[17] U.S. DOE, pg. 13, "Pathways to Commercial Liftoff: Clean Hydrogen," March 2023.
[18] U.S. DOE, pg. 13, "Pathways to Commercial Liftoff: Clean Hydrogen," March 2023.

found that methane emissions can significantly reduce the climate benefit of 'blue' hydrogen in key use cases.[19] As such, 'blue' hydrogen facilities must source natural gas that has eliminated upstream methane emissions to the maximum extent possible.[20] Finally, to further reduce GHG emissions, 'blue' hydrogen facilities should use zero- or low-carbon electricity for any process electricity needs.

While the specific carbon intensity of any hydrogen production facility can differ dramatically based on the inputs discussed above (such as electricity source, upstream methane leaks, and carbon capture rates), this paper is focused on the end-use of such hydrogen. Unless otherwise noted, when we refer to 'low-emissions hydrogen' throughout this paper, this term is intended to encompass both electrolytic and fossil-based production methods that drastically minimize their carbon intensity.

Nascent Decarbonization Technologies for Hydrogen Production

There are several other, earlier-stage natural gas-fired hydrogen production pathways that have lower carbon emissions than conventional pathways: methane pyrolysis, $8RH_2$, and electrified SMR (eSMR).[21] These technologies are currently still in the research and development (R&D) stage and have not been demonstrated at the same scale as the decarbonization pathways discussed previously. While technological breakthroughs are always possible, most hydrogen projections do not include any significant expectations for these nascent production pathways in the next two to three decades. It is important to discuss these production pathways though, as they produce hydrogen from natural gas with a lower carbon intensity than incumbent production. If they scale up faster than expected, these technologies could prove important to the low-emissions hydrogen transition as well.

Methane pyrolysis converts methane into carbon black and hydrogen using high temperatures in an anaerobic reactor or in plasma. The carbon black that is a byproduct of methane pyrolysis is used in a variety of end-uses and can be monetized. Tires, for example, are a third comprised of carbon black and represent 64% of carbon black demand. In 2022, the global market for carbon black was $16 billion, and it is growing by two to three percent annually.[22] If all of the demand for carbon black was met through methane pyrolysis, it would generate enough

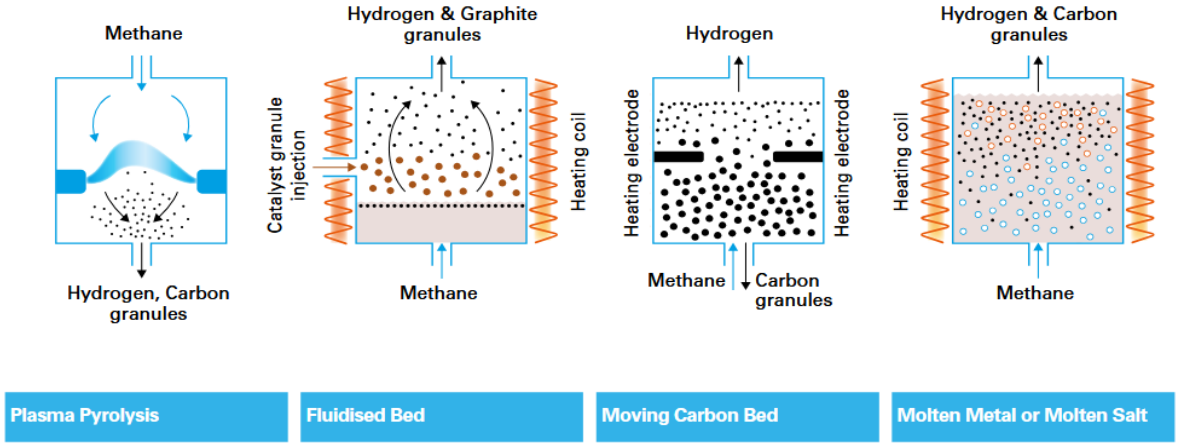
[19] Tianyi Sun, Eriko Shrestha, Steven P. Hamburg, Roland Kupers, and Ilissa B. Ocko, "Climate Impacts of Hydrogen and Methane Emissions Can Considerably Reduce the Climate Benefits across Key Hydrogen Use Cases and Time Scales", Feb. 21, 2024.
[20] Beth Trask, "Blue hydrogen hopes hinge on managing methane emissions", Mar. 3, 2025.
[21] Ammonia Energy Association (AEA), "Technology options for low-emission ammonia production from gas," Oct. 2024.
[22] Monolith, "Monolith Background & H_2 GHG Impact," 2022.

hydrogen to produce 31 million tons of ammonia.[23] Methane pyrolysis does not directly produce CO_2 as the resulting carbon is in the form of carbon black, but it requires about a third more gas than SMR or ATR and a significant energy input. Even still, the process can have a lower carbon intensity—or even a negative carbon intensity—compared to reformation processes depending on the electricity source, the end-use of the carbon black, and the upstream natural gas leakage rate.

There are numerous methane pyrolysis production technologies, but plasma pyrolysis is the most mature. Currently operating in Nebraska, Monolith Materials operates a demonstration plasma pyrolysis plant that produces approximately 5,000 tons of hydrogen per year. A facility that will produce 60,000 tons of hydrogen annually is currently under construction.[24]

FIGURE 2

Process of Methane Pyrolysis[25]



$8RH_2$ and eSMR both replace some of the natural gas combustion used to produce thermal energy during SMR and ATR (which accounts for a third of the overall energy requirement in an SMR) with alternative sources of energy.[26]

$8RH_2$ is like SMR, where methane and steam are fed into a reformer with a nickel-based catalyst to generate hydrogen. This process uses CO_2 as the heat transfer fluid in a CO_2 convective reformer, instead of gas burners like SMR, to generate heat for the reaction. Additional CO_2 produced from methane combustion can be delivered back to the convective reformer at the start of the process for heating, facilitating capture rates over 99%. This technology was

[23] AEA, "Technology options for low-emission ammonia production from gas," Oct. 2024.
[24] AEA, "Technology options for low-emission ammonia production from gas," Oct. 2024.
[25] AEA, "Technology options for low-emission ammonia production from gas," Oct. 2024.
[26] AEA, "Technology options for low-emission ammonia production from gas," Oct. 2024.

developed by 8 Rivers and is akin to the Allam-Fetvedt cycle for power generation.[27] Project Cormorant, led by Casale and 8 Rivers, is a newly constructed ammonia plant featuring hydrogen production via the first commercial-scale 8RH2 deployment. The project is expected to have a final investment decision by early 2025 and aims to produce 880,000 tons of ammonia per year in Port Arthur, Texas.[28]

eSMR uses electric heating instead of gas burners, reducing the amount of natural gas required for the process. eSMR has a start-up time of only a few minutes—compared to hours or even days for conventional SMRs—allowing it to be ramped up and down quickly, which can be done based on the price and availability of renewable electricity. eSMRs can be integrated into existing ammonia plants; they require less space than gas-fired SMRs, but they do require additional equipment, like rectifiers and transformers, to support electric demand.[29]

FIGURE 3

Natural Gas-Based Hydrogen Production Pathways[30]

Technology	Energy requirement		Carbon capture		Size and maturity	
	Gas	Electricity	Capture rate	Added cost	Size	Maturity
SMR	Medium	Low	Medium	High	Medium / Large	High
ATR	Low	Low	High	Medium	Large	High
$8RH_2$	Low	Low	Highest	Low	Large	Low
eSMR	Lowest	High	High	Medium	Small / Medium	Low
Methane pyrolysis	High	High	N/A	N/A	Small / Medium	Low

GHG Abatement Potential in Ammonia Production and Refineries

Together, the ammonia and refining sectors make up approximately 90% of current U.S. hydrogen demand.[31] The U.S. Department of Energy (DOE) projects that there will be 10 MMT of domestic low-emissions hydrogen demand annually by 2030, primarily used for ammonia production, refining, and other chemical processes.[32] If those 10 MMT of low-emissions hydrogen were to replace dirty hydrogen, that could avoid a significant portion of the 100 MMT of CO_2e produced with dirty hydrogen annually.

[27] AEA, "Technology options for low-emission ammonia production from gas," Oct. 2024.
[28] AEA, "8 Rivers in Texas: Deploying 8RH2 technology for carbon capture beyond 99%," May 23, 2024.
[29] AEA, "8 Rivers in Texas: Deploying 8RH2 technology for carbon capture beyond 99%," May 23, 2024.
[30] AEA, "Technology options for low-emission ammonia production from gas," Oct. 2024.
[31] U.S. EIA, "U.S. refiners and chemical manufacturers lead hydrogen production and consumption," Apr. 8, 2024.
[32] U.S. DOE, "Pathways to Commercial Liftoff: Clean Hydrogen," pg. 19, Dec. 2024.

More specifically, ammonia production in the U.S. emits about 46 MMT CO_2 per year.[33] About 85% of those emissions, or 39 MMT CO_2, come from the production of hydrogen from natural gas.[34] If the hydrogen used in ammonia production were replaced by low-emissions hydrogen, it could reduce up to that 39 MMT CO_2 per year.

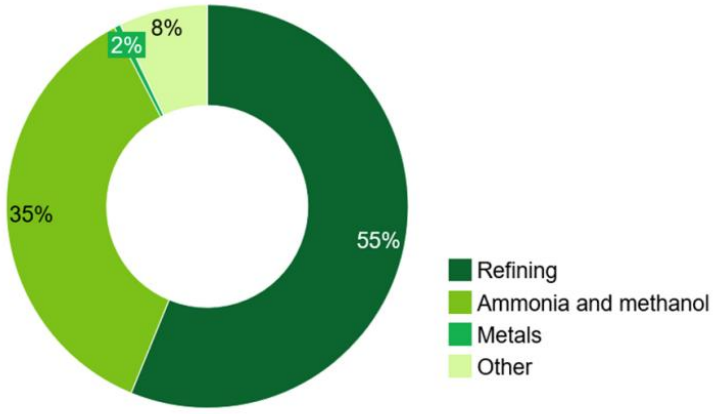
In the refinery sector, U.S. emissions are about 198 MMT CO_2e per year. About 9% of those emissions, or 18 MMT CO_2e, come from on-site production of hydrogen at refineries.[35] Over a 10-year period from 2013 to 2022, the percentage of hydrogen used in refineries that was produced on-site was about 33% (with the remaining 67% coming from merchant hydrogen suppliers).[36] Thus, the total emissions from hydrogen production for use at refineries (including both on-site and merchant) are about 55 MMT CO_2e. If that hydrogen were replaced with low-emissions hydrogen, it could reduce refinery sector emissions by up to 55 MMT CO_2e.[37]

Combined, replacing the current conventional hydrogen used in producing ammonia and at refineries with low-emissions hydrogen could reduce U.S. emissions by up to 94.1 MMT CO_2e, or about 6% of U.S. industrial sector GHG emissions and about 1.5% of the U.S.'s total GHG emissions.

[33] Renewable Thermal Collaborative, pg. 6, "Chemical Sector Decarbonization Roadmap," June 2024.
[34] Mingolla, S., et al., "Effects of emissions caps on the cost and feasibility of low-carbon hydrogen in the European ammonia industry," Nature Communications, 2024.
[35] World Resources Institute (WRI), "A low-carbon future in the U.S. depends on decarbonizing petroleum refineries," Oct. 21, 2021.
[36] U.S. EIA, "U.S. West Coast refinery demand for hydrogen increasingly met by merchant suppliers," May 7, 2024.
[37] Note that using a U.S. DOE source provides similar results. DOE estimates that about 55% of today's U.S. hydrogen production is used in refineries. The U.S. produces about 10 MMT of hydrogen, emitting about 100 MMT of CO_2e. Thus, 55% of those emissions, or 55 MMT CO_2e, can be attributed to hydrogen used at refineries.

FIGURE 4

Hydrogen consumption in the U.S. by end use, 2021[38]



Ammonia is the second most produced chemical in the world.[39] It is a commodity chemical that is typically made by combining feedstocks of nitrogen and hydrogen. The nitrogen is introduced into the synthesis gas stream as ambient air, while the hydrogen is predominantly produced via SMR; today, natural gas is used as the feedstock and fuel to produce hydrogen in 92% of domestic ammonia production. The production of ammonia for fertilizers—by far the most common end use product—accounted for 6.5% of all U.S. industrial natural gas consumption in 2020.[40] The GHG emissions from this process can be mitigated by transitioning to cleaner methods of hydrogen production—either through electrolysis or natural gas combustion that is retrofitted with carbon capture and minimizes upstream and within plant methane leaks.[41]

The refining sector converts crude oil into transportation fuels (like motor gasoline, jet fuel, and liquified petroleum gas) and other petroleum products (such as chemicals and plastics) through a series of energy-intensive chemical processes. Hydrogen is used as a feedstock in many fuel refining processes, including hydrotreating and hydrocracking. Hydrogen is also used to produce some non-fuel products, like plastics, lubricants, and anode grade coke, which is used to make steel and aluminum.[42] Combined, these processes make the refining sector the largest U.S. consumer of hydrogen; 55% of hydrogen consumed in the U.S. is by the refining sector.[43] This hydrogen is almost entirely produced with natural gas.[44]

[38] U.S. DOE, "National Clean Hydrogen Strategy and Roadmap," pg. 14, June 2023.
[39] Liu, X., et al, "Life cycle energy use and greenhouse gas emissions of ammonia production from renewable resources and industrial by-products," Green Chemistry, 2020, vol. 17.
[40] U.S. EIA, "Natural Gas Weekly Update," Apr. 1, 2021.
[41] U.S. EIA, "Natural Gas Weekly Update," Apr. 1, 2021.
[42] Clean Air Task Force, "Hydrogen for Decarbonization: A Realistic Assessment," Nov. 21, 2023.
[43] U.S. DOE, "National Clean Hydrogen Strategy and Roadmap," pg. 14, June 2023.
[44] U.S. EIA, "Hydrogen explained: production of hydrogen," last acc. Feb. 2025.

Hydrogen Use in Ammonia Production

Introduction

This introductory section provides an overview of the ammonia sector, including how it is produced and used, its market characteristics, and the key players in the industry.

Overview of Ammonia

Low-carbon ammonia is being considered as a decarbonization tool for numerous potential uses. While ammonia has been proposed as a direct-use fuel in the shipping and power-generation sectors, there is limited research into the climate impacts of ammonia fuel and low technology readiness level of ammonia engines and generators. Thus, this research focuses on decarbonizing incumbent ammonia production—specifically for use in fertilizers—due to the high-value that replacing incumbent ammonia with cleaner ammonia would have in decarbonizing the existing fertilizer industry.

While ammonia is also used to make other manufactured goods, including plastics, synthetic fibers, cleaning products, and even explosives, fertilizer production dominates demand, accounting for 88% of U.S. ammonia consumption.[45] Current fertilizer production methods are carbon-intensive—most often using 'gray' hydrogen as ammonia's feedstock. For every one metric ton (mt) of ammonia produced, approximately 2.86 mt of CO_2 are emitted in the process.[46] Approximately 85% of these emissions are from producing the hydrogen feedstock through SMR with natural gas.[47] There are limited other decarbonization options for fertilizer production outside of transitioning to low-emissions hydrogen feedstocks. Both factors—the prevalence of emissions from hydrogen production and the limited alternatives—make this use-case a high decarbonization priority for low-emissions hydrogen. Similar to low-emissions hydrogen, clean ammonia is an energy-intensive and limited resource that should be directed toward the best use cases for GHG emission reduction potential. At the same time, other agricultural practices, such as cover cropping and on-farm reduction in fertilizer use, can offer important abatement potential as well—and it is important that ammonia decarbonization does not inadvertently discourage such practices.

Ammonia-based fertilizers are crucial for growing the crops that feed the global population; they are used to produce crops that feed an estimated 3.8 billion people—half of the world's

[45] U.S. DOE, "U.S. National Clean Hydrogen Strategy and Roadmap," pg. 30, 2024.
[46] Yüzbaşıoğlu A, et al., "Decarbonization in ammonia production, new technological methods in industrial scale ammonia production and critical evaluations," Oct 2021.
[47] Mingolla, S., et al., "Effects of emissions caps on the cost and feasibility of low-carbon hydrogen in the European ammonia industry," Nature Communications, 2024.

population.[48] Nitrogen is an essential nutrient for crop growth, but plants can only utilize reduced forms of the element (i.e. as ammonia). Manure, decomposing organic matter, and nitrogen-fixing bacteria all add ammonia to the soil, but they are not sufficient to provide ammonia at the scale needed for global food production, necessitating the use of engineered fertilizers. In 2021, global ammonia demand for fertilizer specifically was 132 MMT.[49]

Based on a tool produced by Clean Air Task Force (CATF), producing today's 132 MMT of ammonia globally requires approximately 23.5 MMT of hydrogen each year. Producing that hydrogen through traditional fossil-based methods requires approximately 88 MMT of natural gas and 110 MMT of water as feedstocks and would emit about 250 MMT of CO_2.[50] As there have been concerns regarding hydrogen-ready offtake sectors for the many announced low-emissions hydrogen production projects in the U.S. and globally, replacing the 23.5 MMT of hydrogen used to produce fertilizer globally with low-emissions hydrogen can provide an immediate offtake opportunity for near-term decarbonization. For context, the 23.5 MMT needed globally for fertilizers alone is more than twice today's total annual hydrogen production in the U.S. (about 10 MMT).

This report focuses on decarbonization of hydrogen and ammonia production and the most beneficial uses of those cleaner fuels and feedstocks; however, further reducing emissions from ammonia-based derivative products and fuels requires subsequent planning across the full value chain. Unless otherwise noted, throughout the remainder of this report, we focus on ammonia production used specifically for fertilizer.

Ammonia can be used as a fertilizer in its pure form (anhydrous ammonia) or in other derivative forms, such as urea and urea-ammonium nitrate (UAN). Some phosphorous fertilizers also contain ammonia. Anhydrous ammonia, which is ammonia with no further processing ("anhydrous" means only that the ammonia compound is not complexed with or dissolved in water), is a common fertilizer in the U.S. due to the prevalence of large-scale farming of nitrogen-intensive crops, like corn. It is also the most economical ammonia fertilizer in the U.S. due to its high nitrogen content and the abundance of domestic natural gas.[51] Anhydrous ammonia is directly injected into the soil where it then converts to an ammonium compound.[52]

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[48] Tonelli et al., "Cost-competitive decentralized ammonia fertilizer production can increase food security," Nature Food, 2024.
[49] Tonelli et al., "Cost-competitive decentralized ammonia fertilizer production can increase food security," Nature Food, 2024.
[50] Clean Air Task Force, "Hydrogen Production Calculator" accessed Dec. 2024.
[51] RMI, "Green Fertilizer Markets and Innovation," Mar. 11, 2025.
[52] University of Minnesota, Minnesota Crop News, "The Three Biggies: Urea, Anhydrous Ammonia, and UAN," Jan. 1, 2024.

Since it does not contain water, it binds to moisture in the soil. This characteristic can also pose a safety hazard, as anhydrous ammonia that is not properly handled can bind to moisture in a person's eyes, throat, lungs, and skin, causing burns akin to frostbite. It must be stored and transported in pressurized tanks and equipment to mitigate these safety risks.[53] Ammonia itself is a gas at room temperature and pressure, but it can be transported as a liquid under high pressure.[54] Domestic transport of ammonia is primarily done by pipeline or specialized railcars.[55] The U.S. is unusual in its use of ammonia directly in soil application during specific seasons, influenced by weather conditions; most countries use ammonia derivatives that require fewer safety controls and that can be applied to crops through spraying or other simplified methods.

Urea is a common ammonia derivative. It is a solid at room temperature—easing transport—and is typically incorporated into the soil through tilling. If left on the surface, especially in warm conditions, it can decompose into ammonia which will evaporate, but tillage reduces these potential losses.[56] Urea is produced by reacting ammonia with CO_2, which is subsequently released into the atmosphere on the farm.[57] Urea is more difficult to decarbonize than other ammonia-based fertilizers, as CO_2 is part of its composition and is released when it is applied to soil. Frequently, to produce urea, the CO_2 is captured from the hydrogen production process and reacted with ammonia to create urea. Eliminating the impact of such on-farm emissions will require either moving away from urea fertilizers or transitioning ammonia production to a process with negative emissions (for example, by sourcing the carbon from direct air capture).[58]

UAN is also a liquid and can be applied to soil through broadcasting, fertigation, or foliar spraying. Like urea, it is prone to volatilization (i.e. evaporating as a gas) if not incorporated into the soil.[59]

Phosphorus fertilizer has lower demand than fertilizers that are predominantly ammonia. The U.S. demand for phosphorus fertilizer has been approximately 8.5 MMT annually since 2007. It is produced by reacting mined phosphate rock with sulfuric acid to produce phosphoric acid.[60]

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[53] Minnesota Department of Agriculture, "Anhydrous Ammonia," accessed Dec. 2024.
[54] National Library of Medicine, "Compound Summary: Ammonia," Dec. 2024.
[55] U.S. EPA, "Anhydrous Ammonia Supply Chain," Dec. 2022.
[56] University of Minnesota, Minnesota Crop News, "The Three Biggies: Urea, Anhydrous Ammonia, and UAN," Jan. 1, 2024.
[57] Ding, J., Ye, R., Fu, Y. et al., "Direct synthesis of urea from carbon dioxide and ammonia," Nature Communications, 2023.
[58] Energy Transitions Commission, pg. 71, "Mission Possible: Reaching net-zero carbon emissions from harder-to-abate sectors by mid-century," Nov. 2018.
[59] University of Minnesota, Minnesota Crop News, "The Three Biggies: Urea, Anhydrous Ammonia, and UAN," Jan. 1, 2024.
[60] U.S. EPA, "TENORM: Fertilizer and Fertilizer Production Wastes," last acc. Feb. 2025.

This can be further reacted with ammonia to produce fertilizer that contains both nitrogen and phosphorus.[61]

Ammonia Market Background

The global ammonia market typically functions like a commodity market—in other words, the prices fluctuate based on global supply and demand. National markets are highly interconnected by trade, making domestic ammonia prices heavily dependent on global prices. It is important to note that the ammonia market and the fertilizer market are intricately connected, as fertilizer production accounts for 88% of U.S. domestic ammonia consumption.[62]

Due to the frequent use of natural gas as a feedstock for ammonia, the cost of ammonia (and thereby fertilizer) is currently tied to the cost of natural gas, which fluctuates based on macroeconomic shifts and international conflicts. This generates a considerable level of price volatility for ammonia; ammonia prices rose by a factor of six between 2020 and 2022 due to numerous factors, including sanctions on Russian exports following Russia's invasion of Ukraine in March of 2022, China reducing their exports of ammonia, and global supply chain disruptions from the COVID-19 pandemic.[63] These price fluctuations in ammonia-based fertilizers can have downstream effects on food prices, as fertilizer constitutes nearly one fifth of U.S. farm cash costs.[64] Therefore, caution (including additional analyses of price effects) should be taken in large undertakings in the ammonia industry, such as decarbonizing the fertilizer market, to avoid inflating downstream food prices for consumers.

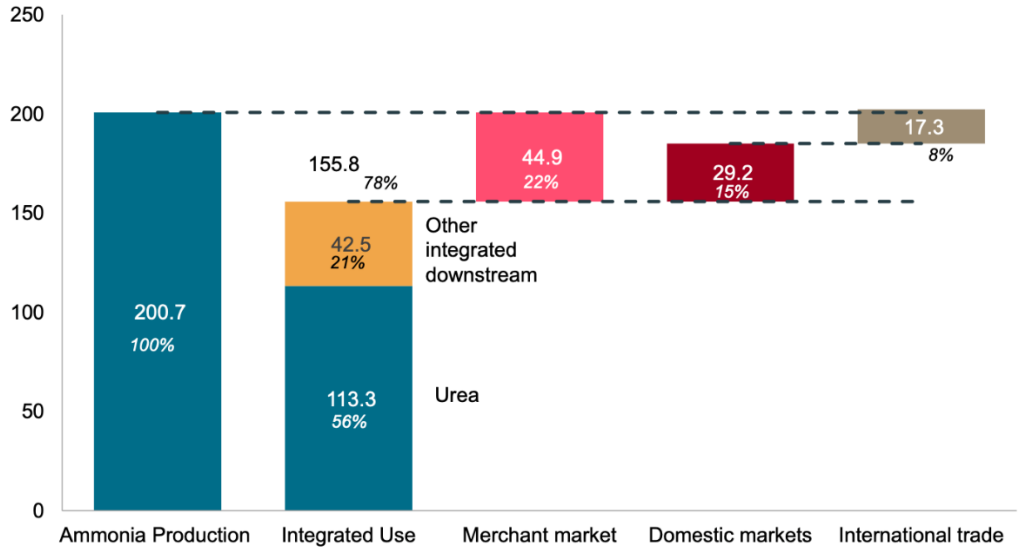
Most ammonia produced globally is consumed on-site to make other products (including ammonia-derived fertilizers), but 22% of ammonia does enter a merchant market to be purchased and consumed by a separate offtaker.[65] These offtakers are either end users (such as other plastics or chemicals producers) or distribution companies that function as middlemen in the ammonia fertilizer market. Yara, BASF, and Koch all serve as distributors.[66]

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[61] University of Minnesota, "Understanding phosphorus fertilizers," last acc. Feb. 2025.
[62] U.S. DOE, "U.S. National Clean Hydrogen Strategy and Roadmap," pg. 30, 2024.
[63] U.S. EIA, "U.S. ammonia prices rise in response to higher international natural gas prices," May 2022; and U.S. Department of Agriculture (USDA), "Impacts and Repercussions of Price Increases on the Global Fertilizer Market," June 2022.
[64] USDA, "Impacts and Repercussions of Price Increases on the Global Fertilizer Market," June 2022.
[65] S&P Global, "The Ammonia Market Today and a Bridge to the Future," Nov. 2024.
[66] S&P Global, "The World's Top 40 Ammonia Buyers: Leading ammonia buyers in 2019 defined by sector and geography," 2020.

FIGURE 5

2024 Global Ammonia Production and Consumption for All Uses (MMT)[67]

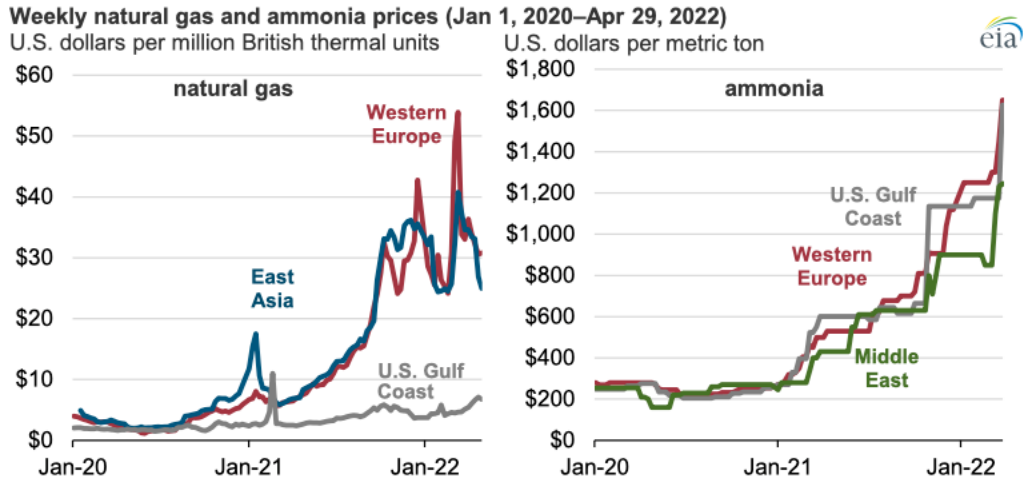


The U.S. currently produces 17 MMT of ammonia annually, positioning it as the third largest producer globally. The largest global producers of ammonia are China (producing 47 MMT per year) and Russia (producing 19 MMT per year).[68] Even with high domestic production of ammonia, the U.S. still imports 14% of its nitrogen-based fertilizer, making it a net importer and the largest importer globally.[69] The reliance on imports further subjects domestic prices of both ammonia and ammonia-based fertilizer to price volatility from shifts in global ammonia prices. As natural gas is the key feedstock for producing conventional ammonia globally and a key component of the overall price of ammonia, the domestic price of ammonia is also subject to shifts in the global price of natural gas.

[67] S&P Global, "The Ammonia Market Today and a Bridge to the Future," Nov. 2024.
[68] U.S. EIA, "U.S. ammonia prices rise in response to higher international natural gas prices," May 10, 2022.
[69] Agricultural & Applied Economics Association, "The History, Consolidation, and Future of the U.S. Nitrogen Fertilizer Production Industry," 2020.

FIGURE 6

Natural Gas and Ammonia Prices[70]



Source: Graph by the U.S. Energy Information Administration, based on data from Bloomberg

In the U.S., ammonia offtake typically operates through spot pricing and shorter-term agreements, particularly in the agricultural sector. Ammonia producers frequently do not sell directly to farmers, but instead sell to wholesalers and retailers, who act as intermediaries between the ammonia producers and farmers. Some ammonia producers (e.g. Nutrien) have retail operations as well, which allow them to sell ammonia and ammonia-derived fertilizers directly to farmers, but this is not the norm.

Some producers and consumers of ammonia do enter into longer-term offtake agreements. For example, some industrial users, including the phosphate fertilizer industry, occasionally secure six-month to one-year agreements. The emerging market for clean ammonia is also driving interest in longer-term offtake agreements to ensure consistent supply both for existing and new uses of ammonia.

Current Key Players

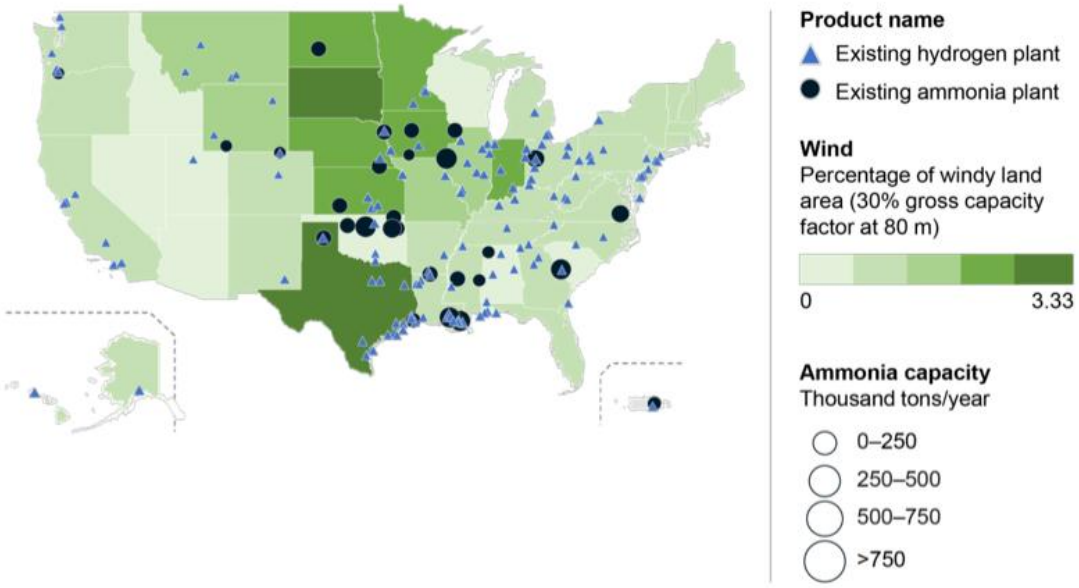
According to the U.S. Energy Information Administration (EIA), there were 32 ammonia plants in the U.S. in 2021, with production spread across 17 states but clustered in the Gulf Coast.[71] Domestic ammonia production for fertilizer is concentrated to a few companies, and in fact, three companies accounted for over 50% of ammonia production in 2023: CF Industries, Nutrien, and Koch.[72]

[70] U.S. EIA, "U.S. ammonia prices rise in response to higher international natural gas prices," May 10, 2022.
[71] U.S. EIA, "Natural Gas Weekly Update," Apr. 1, 2021.
[72] Based on analysis of data provided by Rystad Energy, downloaded in Jan. 2025.

Current production predominantly relies on 'gray' hydrogen, with a small amount of 'blue' hydrogen as well. In 2023, approximately 20 million tons of ammonia were produced in the U.S. with 'gray' hydrogen, compared to 1.5 million tons produced with blue hydrogen.[73]

FIGURE 7

Existing U.S. Hydrogen and Ammonia Production Plants[74]



CF Industries, the largest ammonia producer globally and domestically, had a total, domestic capacity of 6.9 million tons in 2023. This production only uses 'gray' hydrogen.[75] The company's facility in Donaldsonville, Louisiana, which came online in 2016, produces 4.3 million tons of ammonia per year, and is the largest ammonia production facility in the world.[76]

Koch Industries, a privately-owned petrochemical company, produced 1.9 million tons of ammonia in 2023, also all using 'gray' hydrogen as the feedstock.[77] The company recently acquired an additional domestic facility in 2023 when it purchased a plant from OCI Global's Iowa Fertilizer Company. The southeast Iowa plant produces 3.5 million tons of nitrogen fertilizer and diesel exhaust fluid annually.[78]

[73] Based on analysis of data provided by Rystad Energy, downloaded in Jan. 2025.
[74] U.S. DOE, "U.S. National Clean Hydrogen Strategy and Roadmap," pg. 55, 2024.
[75] Based on analysis of data provided by Rystad Energy, downloaded in Jan. 2025.
[76] CF Industries, "Ammonia Production," last accessed Dec. 2024.
[77] Based on analysis of data provided by Rystad Energy, downloaded in Jan 2025.
[78] Donelle Eller, Des Moines Register, "OCI Global sells Iowa Fertilizer Co. plant to Koch Industries for $3.6 million," Dec. 19, 2023.

A global fertilizer company, Nutrien's domestic operations totaled 2.8 million tons of ammonia in 2023, with a small fraction using 'blue' hydrogen and the majority sourcing from 'gray' hydrogen.[79]

Growth in the Ammonia Market

Domestic ammonia production grew considerably over the past decade, increasing from 11.6 MMT in 2015 to 17 MMT in 2021.[80] The growth of this sector is projected to continue as demand for nitrogen-based fertilizers is forecasted to increase and ammonia is expected to serve as a decarbonization lever across multiple sectors.

By 2050, ammonia demand is projected to triple, and nearly all growth in demand could be met by low-carbon supply.[81] As of August 2024, the U.S. was projected to be the largest producer of clean ammonia by 2030, producing 11.1 MMT per year.[82] This new demand could also transform the dynamics of the global ammonia market. While most ammonia today is consumed on-site to create final manufactured products (often, fertilizers), low-carbon ammonia is expected to be more frequently traded as a commodity.[83]

Ammonia Production Pathways and Emissions

Current Ammonia Production Pathways

Ammonia production can occur at integrated facilities that produce ammonia directly from natural gas (with hydrogen as an intermediate feedstock) or at ammonia-specific facilities that purchase a supply of hydrogen from a separate entity. Both of these processes in the U.S. overwhelmingly rely on natural gas-fired SMR to produce hydrogen.

Ammonia is produced by taking hydrogen, usually created via SMR, and reacting it with nitrogen through a high heat, high pressure reaction process called the Haber-Bosch process. There are six process steps in ammonia production: natural gas desulfurization, steam reforming, carbon monoxide shift, carbon dioxide removal, methanation, and ammonia synthesis. The first, third, fourth, and fifth steps remove impurities such as sulfur, carbon monoxide, carbon dioxide, and water vapor from the feedstock, hydrogen, and synthesis gas streams. In the second step, hydrogen is produced, and nitrogen—typically from air—is

[79] Based on analysis of data provided by Rystad Energy, downloaded in Jan 2025.
[80] U.S. EIA, "Natural Gas Weekly Update," Apr. 1, 2021; and U.S. EIA, "U.S. ammonia prices rise in response to higher international gas prices," May 10, 2022.
[81] Renewable Thermal Collaborative, "Chemical Sector Decarbonization Roadmap," pg. 18, June 2024.
[82] BloombergNEF (BNEF), "Ammonia Supply Outlook 2024: A Clean Takeover," Aug. 8, 2024. Note that this analysis was released before 2025 changes to the 45V Hydrogen Production Tax Credit, which limited the timeline for project eligibility.
[83] Renewable Thermal Collaborative, "Chemical Sector Decarbonization Roadmap," pg. 18, June 2024.

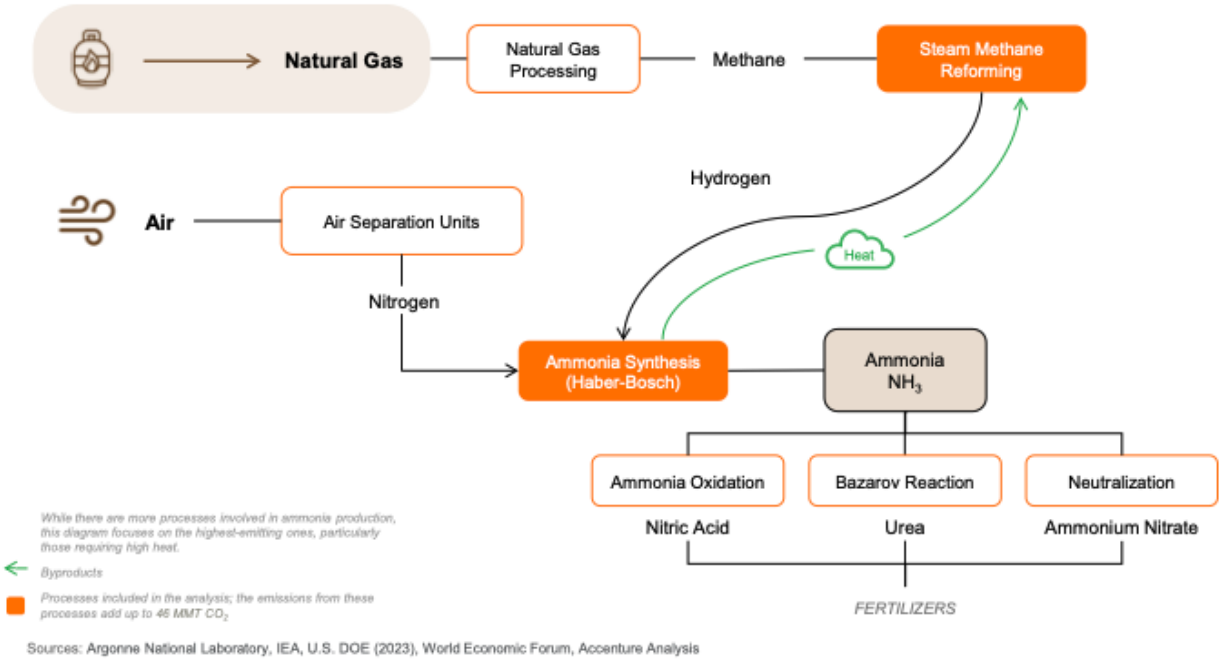
introduced into the system. In the final step, synthetic gas is converted into anhydrous ammonia.[84]

During steam reforming, approximately 70% of the natural gas is converted to hydrogen and carbon dioxide, and an additional amount of natural gas produces carbon monoxide. The process gas then enters the carbon monoxide shift process, reacting water with carbon monoxide to produce additional carbon dioxide and hydrogen. The carbon dioxide that is produced during these first three steps—the majority of which is produced during steam reforming—is expelled into the atmosphere during the carbon dioxide removal step.[85]

Overall, the Haber-Bosch process is an energy intensive process; it accounts for 1% of global energy demand. The process reacts nitrogen with hydrogen at 500° C and up to 20 megapascal (MPa) to form ammonia. [86] It is an exothermic reaction, releasing heat that can be reused in natural gas SMR.[87]

FIGURE 8

Ammonia Production Process [88]



Sources: Argonne National Laboratory, IEA, U.S. DOE (2023), World Economic Forum, Accenture Analysis

[84] U.S. EPA, "AP-42, Chapter 8.1: Synthetic Ammonia," 1993.
[85] U.S. EPA, "AP-42, Chapter 8.1: Synthetic Ammonia," 1993.
[86] Capdevila-Cortada, Marcal, Nature, "Electrifying the Haber-Bosch," Dec. 2019.
[87] Renewable Thermal Collaborative, "Chemical Sector Decarbonization Roadmap," pg. 18, June 2024.
[88] Renewable Thermal Collaborative, "Chemical Sector Decarbonization Roadmap," pg. 19, June 2024.

GHG Emissions from Ammonia Production

Domestic ammonia production accounted for 46 MMT of CO_2 emissions in 2021.[89] The most efficient ammonia production facilities emit 1.6 tons of CO_2 per ton of ammonia, while the global average rate is 2.86 tons of CO_2 per ton of ammonia.[90] Within the production process, 13% of emissions are from producing thermal energy (typically by burning natural gas), 60% are process emissions, and 27% are from use of electricity.[91] It is worth noting that ammonia facility emissions include the emissions from production of hydrogen only when hydrogen is produced on-site. Otherwise, if the hydrogen feedstock is purchased from a merchant supplier, the emissions from the production of the hydrogen would be included in a full lifecycle assessment of the GHG intensity of ammonia but would not typically be included in an ammonia facility's emissions.

While process emissions are a result of both the SMR and Haber-Bosch steps, SMR is a more carbon-intensive process. Approximately 85% of CO_2e emissions (which includes CO_2 and other GHG emissions) from ammonia production are from the production of the hydrogen feedstock from natural gas.[92]

Ammonia Decarbonization Methods & Commercialization Pathways

According to the Renewable Thermal Collaborative (RTC), the ammonia sector may be able to decarbonize its GHG emissions by up to 60% by 2050 using a combination of low-emissions hydrogen feedstocks (i.e., electrolytic hydrogen, natural gas with CCS and strict upstream methane leak controls, and waste biomass).[93] In addition, the U.S. DOE found that the ammonia market is expected to be one of the early adopters and opportunities for large-scale demand for low-emissions hydrogen. They found that decarbonizing domestic, conventional demand for ammonia (mainly fertilizer production) could use 4 to 5 MMT per year of clean hydrogen.[94] However, as is discussed later in the Policy section, this expected uptake is dependent on some key barriers—particularly, cost discrepancies with incumbent production methods—being overcome with policy and market mechanisms.

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[89] Renewable Thermal Collaborative, "Chemical Sector Decarbonization Roadmap," pg. 6, June 2024.
[90] Yüzbaşıoğlu A, et al., "Decarbonization in ammonia production, new technological methods in industrial scale ammonia production and critical evaluations," Oct 2021.
[91] Renewable Thermal Collaborative, pg. 19, "Chemical Sector Decarbonization Roadmap," June 2024.
[92] Mingolla, S., et al., "Effects of emissions caps on the cost and feasibility of low-carbon hydrogen in the European ammonia industry," Nature Communications, 2024.
[93] Renewable Thermal Collaborative, pg. 4, "Chemical Sector Decarbonization Roadmap", June 2024.
[94] U.S. DOE, "U.S. National Clean Hydrogen Strategy and Roadmap," pg. 21, June 2023.

Existing Ammonia Decarbonization Technologies

Ammonia producers can switch out current natural gas-derived hydrogen with low-emissions hydrogen without compromising the final product or its efficacy, as ammonia derived from low-emissions hydrogen is identical to traditional ammonia. There are 25 announced low-emissions hydrogen projects in the U.S. intended for use in ammonia production. While this ammonia is not specifically for fertilizer production, fertilizer still represents most of the demand for ammonia. These projects are divided between electrolytic and fossil SMR with carbon capture, totaling 3.5 MMT per year of production.[95]

Some low-emissions hydrogen projects in the U.S. that are focused on the fertilizer industry include:

- *CF Industries Electrolysis Project*. CF Industries, introduced earlier in this report, is integrating electrolytic hydrogen production at its ammonia production facility in Donaldsonville, Louisiana—the largest ammonia production facility in the world, currently producing 4.3 million tons of ammonia derived from 'gray' hydrogen annually. The facility has six ammonia plants, five urea plants, four nitric acid plants, three urea ammonium nitrate plants, and a diesel exhaust fluid plant, producing eight million tons of nitrogen products annually for both agricultural and industrial use. The plant is commissioning a small electrolyzer that will operate alongside its natural gas-based hydrogen production.
- *CF Industries Carbon Capture Project*. CF Industries is retrofitting two SMR processes in their Donaldsonville facility with CCS. These production pathways using 'blue' hydrogen—along with a retrofit to an SMR facility in Yazoo City, MS—were announced 2021. The Donaldsonville complex will capture two million tons of CO_2 annually and plans to transport it by pipeline to permanent sequestration.
- *Woodside Beaumont Facility*. Woodside is acquiring a 'blue' ammonia production facility currently under construction from OCI in Beaumont, Texas that will use ATR with CCS. The plant is set to begin production of ammonia in 2025 and low-carbon ammonia in 2026, aiming to capture 95% of carbon emissions and reduce emissions by 3.2 MMT CO_2 per year.[96]

[95] U.S. DOE, pg. 21, "Pathways to Commercial Liftoff: Low-emissions hydrogen," Dec. 2024.
[96] Woodside Energy, "Woodside to acquire OCI's clean ammonia project," Aug. 2024.

- *Nutrien's Paused ATR with CCS Plans*. Nutrien planned to construct an ammonia production facility in Geismar, Louisiana that used ATR with CCS, but the company paused their plans in 2023. The facility was expected to produce 1.2 million tons of low-carbon ammonia per year. Nutrien had an offtake agreement with Mitsubishi for up to 40% of the production for use as a fuel in Asia, but there was too much uncertainty in the emerging clean ammonia market for Nutrien to continue with the investment.[97]

Expected Ammonia Decarbonization

Ammonia fertilizer is a low-profit margin commodity, which makes it challenging for ammonia producers to invest in expensive decarbonization equipment. In particular, the sector is limited in its ability to cost-effectively transition to electrolytic hydrogen production, which has high capital costs and is dependent on electricity prices for operational costs.[98]

According to the U.S. DOE, incumbent uses of ammonia such as fertilizers are projected to drive the demand for low-carbon ammonia. This expectation is based on incumbent sectors' existing technology and infrastructure readiness, which means it is immediately technically feasible for them to use low-emissions hydrogen. Incumbent industries' readiness is particularly relevant at facilities where the hydrogen and ammonia production are co-located, easing the physical challenges and economic costs of the transition.[99] However, low-emissions hydrogen (especially electrolytic hydrogen) still faces a notable "willingness to pay" barrier from ammonia fertilizer purchasers, which will be discussed further in the Barriers and Policy sections, below.

At least in the short-term, it could be more likely that the domestic ammonia market will deploy CCS to decarbonize the current production of its hydrogen feedstocks, which is currently cheaper than purchasing and running electrolyzers. For example, in a "high ammonia uptake scenario", North America could produce 12.7 MMT annually of 'blue' ammonia by 2030, and the U.S. could account for 80% of this North American supply.[100]

Somewhat counterintuitively, the use of low-emissions hydrogen in incumbent sectors first could cause global supply growth to lag, as clean hydrogen would replace traditional demand in fertilizers and chemicals rather than supporting growth of new applications. In many cases, it is the newer applications (again, often with higher willingness to pay) that have caused the increase in low-emissions hydrogen and clean ammonia project announcements; however,

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[97] Polly Martin, Hydrogen Insight, "'World's largest' blue hydrogen-based ammonia project due to increased costs and lack of market," Aug. 11, 2023.
[98] U.S. DOE, pg. 20, "Pathways to Commercial Liftoff: Clean Hydrogen," December 2024.
[99] U.S. DOE, pg. 19, "Pathways to Commercial Liftoff: Clean Hydrogen," March 2023.
[100] BNEF, "Ammonia Supply Outlook 2024: A Clean Takeover," Aug. 8, 2024. It is important to note that this analysis is from 2024, and progress in the ammonia market since then has been slower than expected.

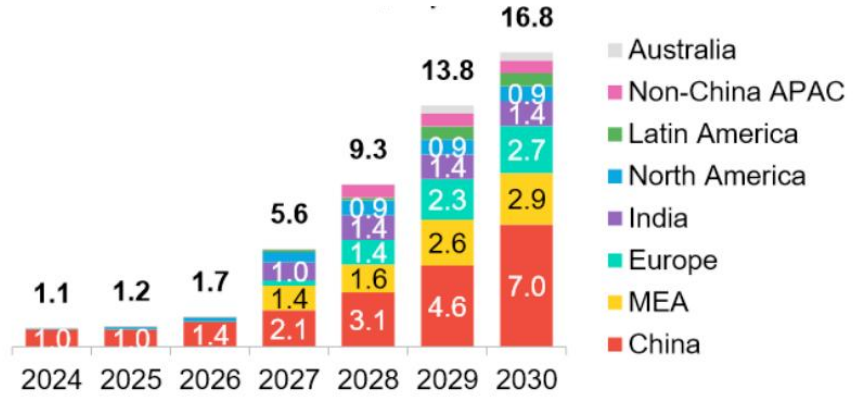
despite this interest, many announced clean ammonia projects have yet to secure offtakers. As a result, it is possible that these projects may instead be directed toward replacing conventional hydrogen production in incumbent industries, rather than catering to new demand—potentially slowing the overall supply growth in ammonia.[101] Depending on the alternative decarbonization pathways for the newer applications, if directing available low-emissions hydrogen to fertilizer production first means that potential users in the power sector decide to decarbonize via clean electricity sources rather than combusting low-emissions hydrogen or ammonia to generate electricity, that shift would likely come with climate benefits and infrastructure and cost efficiencies.

As the market for low-carbon ammonia develops, U.S. production is also expected to target exports. In 2030, almost 70% of low-carbon ammonia production is expected to be exported. This demand is driven by clean energy goals and emissions regulations in other countries, particularly in regions where renewable energy capacity is limited, such South Korea and Japan. These global policies have the potential to shape the trajectory of U.S. clean ammonia production. For example, SMR with carbon capture may not be eligible for South Korea's hydrogen power auction, which requires 'blue' ammonia to capture at least 90% of emissions. 'Blue' ammonia will likely have to be produced through ATR to comply with this standard and maintain an export market with South Korea.[102] As the domestic fertilizer industry aims to decarbonize, these global dynamics can help by aiding expansion of clean ammonia production in the U.S. and pushing U.S. producers to meet more stringent emissions reductions than they might otherwise (given the lack of U.S. domestic regulation). But global dynamics can also hurt, by creating international competition for the limited available clean ammonia supply.

[101] BNEF, "Ammonia Supply Outlook 2024: A Clean Takeover," Aug. 8, 2024.
[102] BNEF, "Ammonia Supply Outlook 2024: A Clean Takeover," Aug. 8, 2024.

FIGURE 1

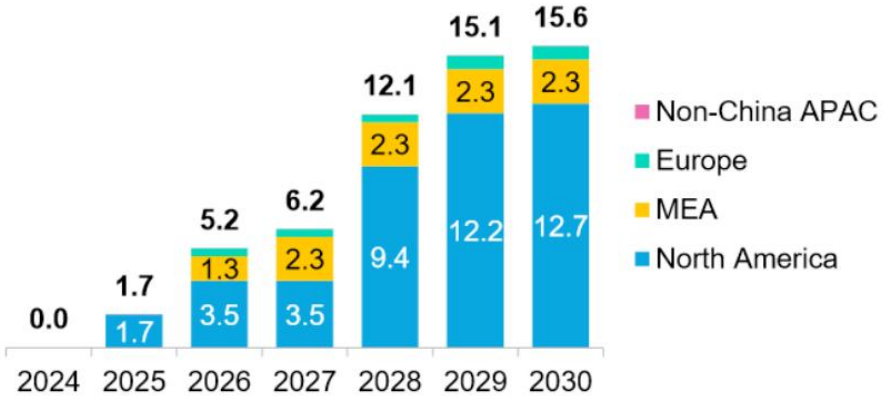
'Green' Ammonia Supply Outlook Under Bloomberg New Energy Finance (BNEF) High Uptake Scenario (MMT per year) [103]



Source: BloombergNEF. Note: 'APAC' stands for Asia-Pacific. 'MEA' stands for Middle East and Africa.

FIGURE 2

'Blue' Ammonia Supply Outlook Under BNEF's High Scenario (MMT per year) [104]



Source: BloombergNEF. Note: 'APAC' stands for Asia-Pacific. 'MEA' stands for Middle East and Africa.

[103] BNEF, "Ammonia Supply Outlook 2024: A Clean Takeover," Aug. 8, 2024.
[104] BNEF, "Ammonia Supply Outlook 2024: A Clean Takeover," Aug. 8, 2024.

Hydrogen Use in the Refining Sector

Introduction

This introductory section provides an overview of the refining sector, including demand for refinery products, emissions from refineries, the market for refining products, and current key players in the industry.

Overview of Refining

The refining sector is a part of the global oil and gas industry. While decarbonization of other sectors of the economy will reduce the demand for traditional refining end products over time, the current demand for refining products will not disappear overnight. Petrochemicals are expected to make up nearly half of the growth in oil demand globally by 2050, while transportation fuels will make up the other half of growth.[105] Similarly, there were 296 million cars registered in the U.S. in 2024, and a study by Princeton researchers found that even in an ambitious electrification scenario, 20% of motor gasoline demand will remain in 2050.[106] The uptake of alternative fuels will also maintain demand for refining processes and the hydrogen that they require, as biofuels—such as those made from waste biomass and those used in sustainable aviation fuel—are similar to petroleum fuels in that they must be refined before they can be used. Thus, refining practices will need to shift to lower-carbon alternatives wherever feasible as refineries continue to operate until 2050 and beyond.

Reducing the carbon intensity of refining processes will also help fuel producers comply with existing policies like low carbon fuel standards (LCFS). Three states—California, Washington, and Oregon—have adopted a LCFS, and seven others have had legislation introduced to establish one.[107]

Estimates of current and projected hydrogen production in the U.S. can range based on data source, thus the amount of that hydrogen that is currently used by refineries in the U.S. can range by source as well. For example, in DOE's Pathways to Commercial Liftoff report for Clean Hydrogen, DOE states that there will be 7.5 MMT of hydrogen demand for refineries in 2030, which was based on demand staying relatively constant from 2024.[108] In DOE's National Clean Hydrogen Strategy and Roadmap, it states that there is 10 MMT of hydrogen produced annually in the U.S., with 55% (or 5.5 MMT) going to the refining sector. DOE's Roadmap also notes that

[105] IEA, "The Future of Petrochemicals", October 2018.
[106] Hedges & Company, "U.S. Vehicle Registration Statistics," last accessed March 2025; and Princeton University, "The Net-Zero America project", Oct. 29, 2021.
[107] RMI, "How States Can Use Low-Carbon Fuel Standards to Incentivize Clean Hydrogen-Derived Fuels," Feb. 9, 2024.
[108] U.S. DOE, "Pathways to Commercial Liftoff: Clean Hydrogen," pg. 33, Dec. 2024.

total hydrogen production in the U.S. could be higher than 10 MMT, as some hydrogen is produced and used at the same facility and is the byproduct of other processes.[109]

The refining sector can drastically reduce its emissions by transitioning its hydrogen production—which is currently reliant on natural gas—to cleaner production pathways. The U.S. refining sector produces emissions of about 198 MMT of CO_2e annually, equating to three percent of annual U.S. emissions.[110] Approximately nine percent of the sector's emissions are from the production of hydrogen through natural gas SMR when the hydrogen is produced on-site at a refinery.[111] As with ammonia production, unless a full lifecycle product or fuel assessment is used, a refinery's facility emissions *only* include emissions from hydrogen production when that hydrogen is produced on-site, rather than purchased from a merchant supplier.

The refining sector is responsible for between 15 and 20% of the lifecycle carbon emissions of motor gasoline, diesel, and jet fuel.[112] The fuel's combustion at its end use generates the largest portion of its emissions. Motor gasoline, for example, has a CO_2e intensity of 89 grams per megajoule (g CO_2e/MJ); 17 g/MJ are generated during extraction and refining while 71 g/MJ are generated by combustion, with the remaining emissions coming from blending and transportation. While decarbonizing the refining sector is crucial, it is worth noting that it represents only a small portion of the lifecycle emissions of fossil fuels.

Refining Market Background

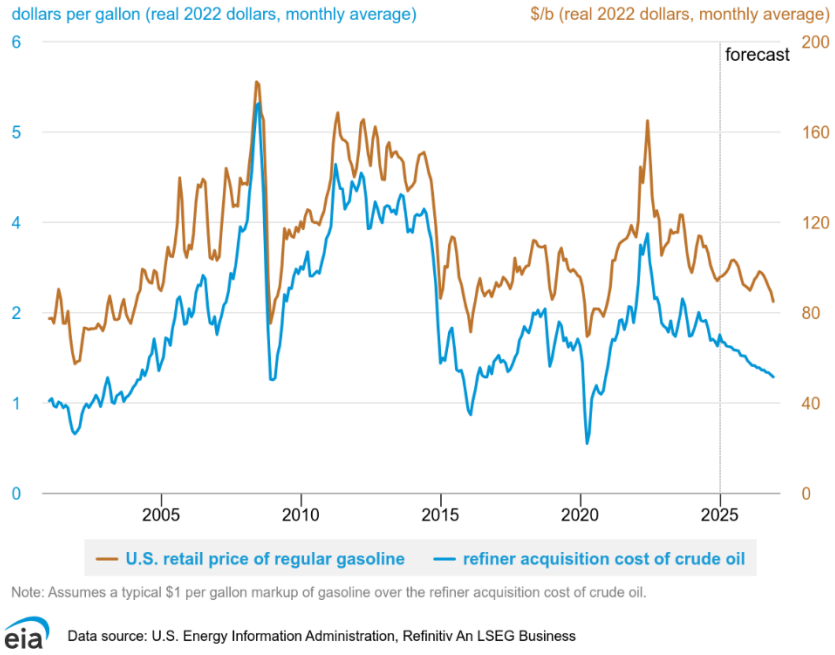
Like the ammonia sector, the refining sector is a global commodity market. Crude oil prices globally move closely together with slight variations depending on sulfur content. The prices have drastic downstream effects; the price of crude oil is a primary driver of the prices of refined petroleum products, like gasoline.

The price of crude oil—and therefore petroleum products—is extremely volatile. It is affected by geopolitical and weather-related events that have the potential to disrupt the flow of oil to the market. This volatility occurs because oil production capacity and the infrastructure that relies on petroleum are largely fixed, making it difficult to quickly increase supply or reduce consumption when prices rise. As a result, even small disruptions—like increased demand for heating oil in the winter—can lead to significant price swings.[113]

[109] U.S. DOE, "National Clean Hydrogen Strategy and Roadmap," pg. 14, June 2023.
[110] WRI, "A low-carbon future in the U.S. depends on decarbonizing petroleum refineries," Oct. 21, 2021.
[111] WRI, "A low-carbon future in the U.S. depends on decarbonizing petroleum refineries," Oct. 21, 2021.
[112] WRI, "Technological Pathways for Decarbonizing Petroleum Refining," pg. 5, Sept. 2021.
[113] U.S. EIA, "What drives crude oil prices: Spot prices," last accessed Feb. 2024.

FIGURE 3

U.S. retail regular gasoline price and refiner acquisition cost of crude oil[114]



The international oil and gas market has three segments: upstream, midstream, and downstream. While some oil and gas companies have activities in only one of these segments, many—including many major U.S. producers—are integrated, meaning that they operate in all market segments. BP, Chevron, ExxonMobil, and Royal Dutch Shell are all integrated companies.[115]

The upstream market comprises businesses that participate in oil and gas exploration and production, such as Occidental Petroleum**.** The midstream market includes companies like Kinder Morgan and Enbridge, who transport oil and gas with ships and pipelines. Downstream companies, such as Marathon Petroleum and Valero Energy, conduct only the refining and marketing of final products.[116]

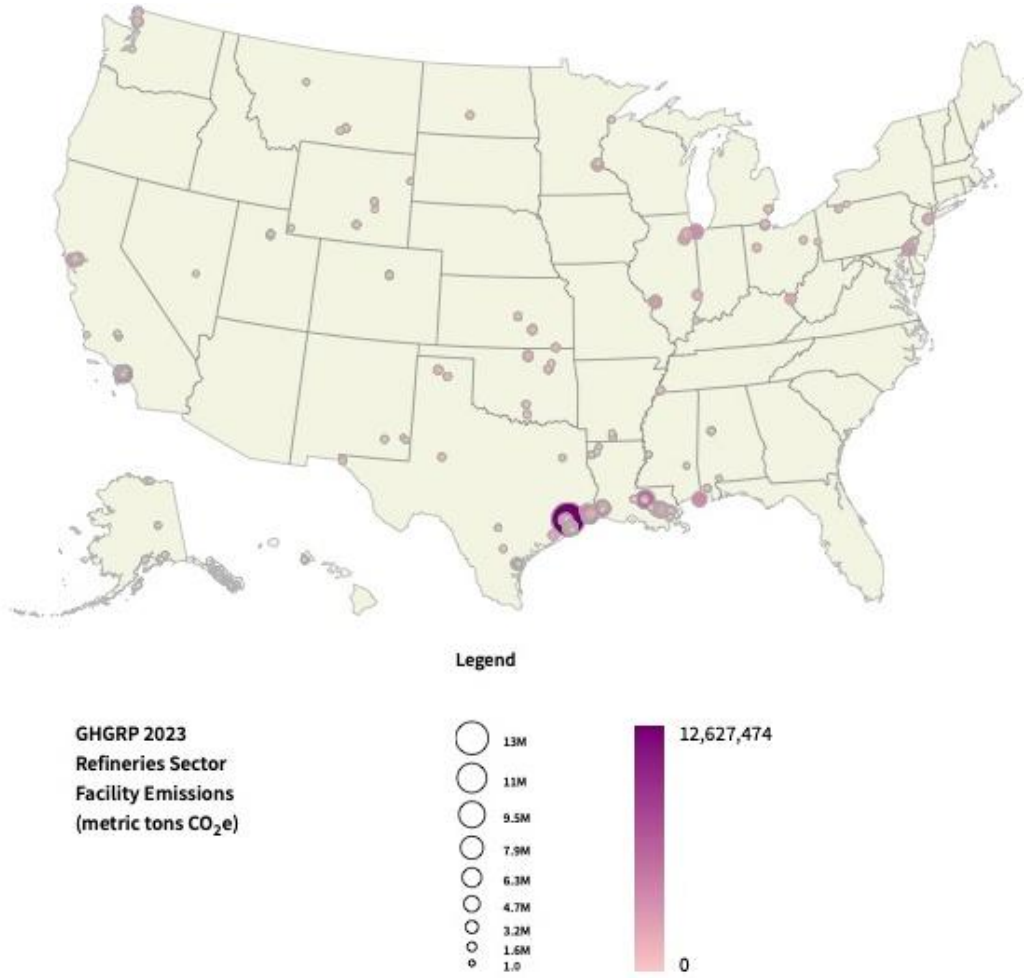
In 2022, refineries in the U.S. produced 18.7 million barrels of finished petroleum products daily.[117] 51 companies own refineries in the U.S., with a combined 132 operable refineries in

[114] U.S. EIA, "What drives crude oil prices: Spot prices," last updated Feb. 2024.
[115] U.S. Library of Congress, "Oil and Gas Industry: A Research Guide," last acc. Feb. 2025.
[116] U.S. Library of Congress, "Oil and Gas Industry: A Research Guide," last acc. Feb. 2025.
[117] U.S. DOE, pg. 11, "Pathways to Commercial Liftoff: Decarbonizing Chemicals & Refining," Sept. 2023.

2024.[118] Refineries are located across 30 states, but they are concentrated in Southern California, the Midwest, and the Gulf Coast; Texas and Louisiana alone house 44 refineries.[119]

FIGURE 4

Refineries in the U.S. and their GHG emissions[120]



Refineries in the U.S. either procure their hydrogen from merchant suppliers or produce it themselves. In 2022, merchant suppliers met 70% of U.S. refinery hydrogen demand, the highest percentage since the U.S. EIA began publishing the data in 2009.[121]

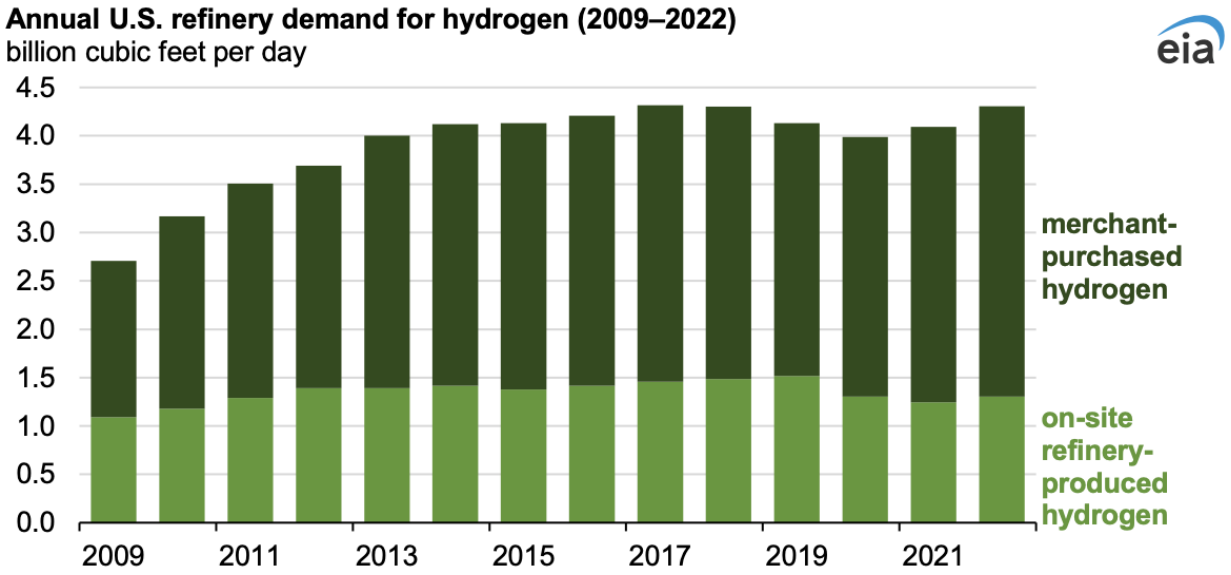
Industrial gas companies, such as Air Products and Linde, operate hydrogen production facilities near refineries to ease transportation.[122] Even when the refinery purchases hydrogen

[118] U.S. EIA, "When was the last refinery built in the United States?" last acc. Feb. 2025. Company count is based on the U.S. EIA's 2024 U.S. Refinery Rankings.
[119] Based on U.S. EIA's 2024 U.S. Refinery Rankings.
[120] U.S. EPA, "Greenhouse Gas Reporting Programs: Refineries," last updated August 2024.
[121] U.S. EIA, "U.S. West Coast refinery demand for hydrogen increasingly met by merchant suppliers," May 7, 2024.
[122] U.S. DOE, "Current Hydrogen Market Size: Domestic and Global," Oct. 2019.

from a merchant producer, hydrogen production could still occur onsite. Some merchant suppliers own and operate SMR units inside the refinery.[123] In 2018, 55 out of the 139 refineries in the U.S. had an SMR onsite.[124]

FIGURE 5

Annual U.S. refinery demand for hydrogen[125]



Current Key Players

Over 50% of the refining production capacity in the U.S. is concentrated in the top five companies.[126] The largest refining companies in the U.S. (by daily production volume, from highest to lowest) are Marathon Petroleum, Valero Energy, ExxonMobil, Phillips 66, PBF Energy, and Chevron. Each of these companies refines over one million barrels of crude oil daily domestically.[127]

[123] U.S. EIA, "U.S. West Coast refinery demand for hydrogen increasingly met by merchant suppliers," May 7, 2024.
[124] WRI, pg. 9, "Technological Pathways for Decarbonizing Petroleum Refining," Sept. 2021.
[125] U.S. EIA, "U.S. West Coast refinery demand for hydrogen increasingly met by merchant suppliers," May 7, 2024.
[126] U.S. DOE, pg. 11, "Pathways to Commercial Liftoff: Decarbonizing Chemicals & Refining," Sept. 2023.
[127] Based on U.S. EIA's 2024 U.S. Refinery Rankings.

TABLE 1

Six largest refining companies, by daily production volume[128]

Company	Daily U.S. Capacity (in barrels of crude oil)	Number of Refineries in the U.S.	Locations of Refineries
Marathon Petroleum	2,945,000	13	Alaska, California, Illinois, Kentucky, Louisiana, Michigan, Minnesota, North Dakota, Ohio, Texas, Utah, Washington
Valero	2,206,300	13	California, Louisiana, Oklahoma, Tennessee, Texas
ExxonMobil	1,947,764	4	Illinois, Louisiana, Texas
Phillips 66	1,387,048	8	California, Louisiana, Montana, New Jersey, Oklahoma, Texas, Washington
PBF Energy Co	1,042,200	7	California, Delaware, Louisiana, New Jersey, Ohio
Chevron	1,037,660	4	California, Mississippi, Texas, Utah

Refining Pathways and Emissions

Current Refining Pathways

The refining process is a series of chemical reactions that converts heavy crude oil into higher-value lighter products by breaking apart long hydrocarbon chains and removing impurities like sulfur, nitrogen, and oxygen. Hydrogen is used for both of these processes.

The exact steps in the refining process differ based on the desired fuel product, but, generally, there are three major steps: distillation, conversion, and treatment. Hydrogen is used in both conversion and treatment. Not all final refinery products undergo all three steps. Diesel fuels, for example, only undergo distillation and desulfurization with hydrogen while other products are further refined.[129]

[128] Based on U.S. EIA's 2024 U.S. Refinery Rankings.
[129] WRI, pg. 4, "Technological Pathways for Decarbonizing Petroleum Refining," Sept. 2021.

During the first distillation step, the crude oil is piped through hot furnaces, using the differing boiling points of petroleum components to separate them. The resulting liquids and gases are then discharged into distillation units, where heavy fractions with higher boiling points—like residual fuel oil and heavy gas oil—sink to the bottom and lighter fractions with lower boiling points—like butane and gasoline—rise to the top.[130]

The conversion step is the further processing, through chemical reactions, of heavier and generally lower value distillation products into lighter and higher value products. This process is conducted in either a fluid catalytic cracker or a hydrocracker. Fluid catalytic crackers use a solid sand-like catalyst that is made fluid by vapor to break apart gas oil into smaller molecules that make up gasoline, distillate, and other higher-value end products.[131]

Comparatively, hydrocrackers react hydrogen—along with heat, pressure, and catalysts—with the longer hydrocarbon chains to generate smaller, lighter ones. This process is called hydrocracking.[132] Some products, like heavy gas oil, are processed in a fluid catalytic cracker and are further cracked in a hydrocracker.[133] The resulting intermediary products from the conversion step are referred to as streams.[134]

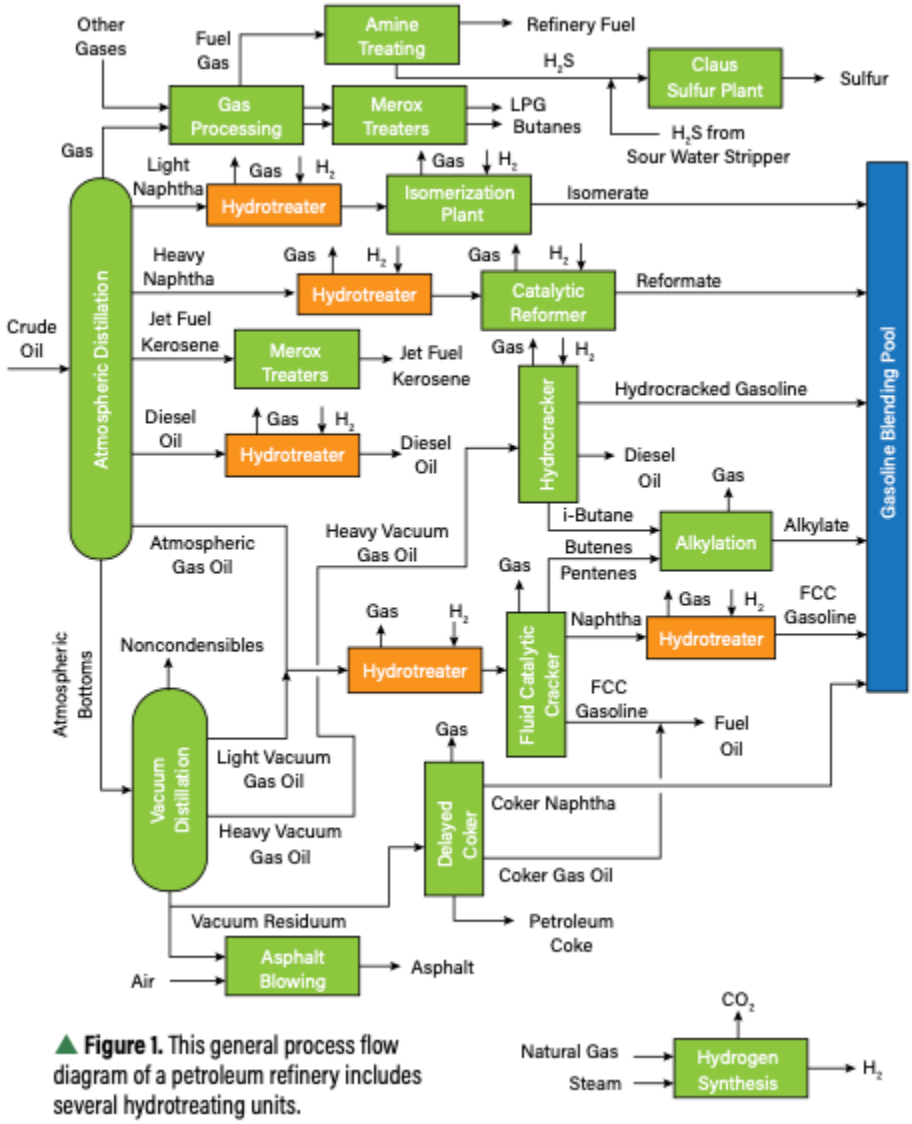
The final step, treatment, consists of blending a variety of streams to create final products.[135] The ratio of the streams varies depending on current demand for certain products.

Throughout the refining process, the fuels are hydrotreated, which involves using hydrogen to remove impurities like sulfur, nitrogen, oxygen, olefins, and heavy metals from fuels. This process allows fuels to comply with technical, government, and safety requirements. There are standards that limit the amount of sulfur and other elements in fuels to reduce the production of harmful pollutants such as nitrogen oxides (NOx) and sulfur oxides (SOx). Hydrotreating also increases the efficiency of fuels, as contaminants can affect the performance of downstream unit operations, catalysts, and even engines.[136]

[130] U.S. EIA, "Oil and petroleum products explained: refining crude oil," last acc. Feb. 2025.
[131] U.S. EIA, "Fluid catalytic cracking is an important step in producing gasoline," Dec. 2012.
[132] U.S. EIA, "Oil and petroleum products explained: refining crude oil," last acc. Feb. 2025.
[133] U.S. EIA, "Fluid catalytic cracking is an important step in producing gasoline," Dec. 2012.
[134] U.S. EIA, "Oil and petroleum products explained: refining crude oil," last acc. Feb. 2025.
[135] U.S. EIA, "Oil and petroleum products explained: refining crude oil," last acc. Feb. 2025.
[136] American Institute for Chemical Engineers, "An Overview of Hydrotreating," Oct. 2021.

FIGURE 6

Process flow diagram of a petroleum refinery[137]



▲ **Figure 1.** This general process flow diagram of a petroleum refinery includes several hydrotreating units.

GHG Emissions from Hydrogen Usage in Refining

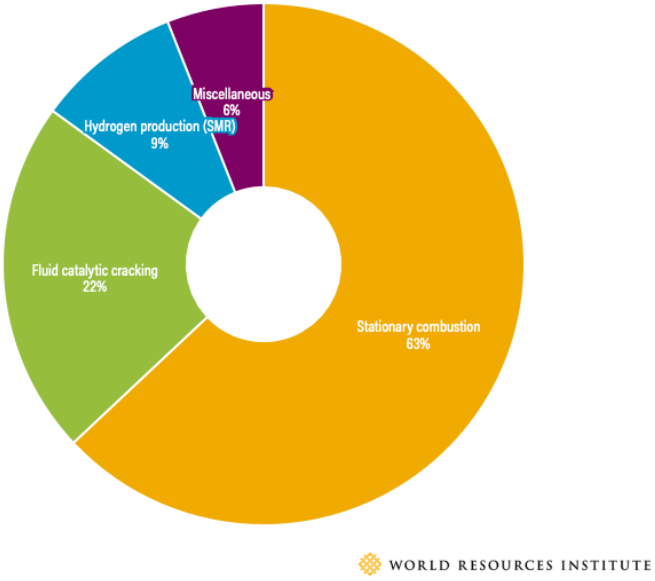
The largest sources of process emissions—emissions that are created during chemical reactions that are inherent to production and excluding stationary combustion—during refining are from fluid catalytic crackers and the production of hydrogen with SMRs. Hydrogen production accounts for approximately nine percent of onsite refinery emissions, and as noted previously, this does not make up the total emissions from hydrogen produced in the U.S. and used at

[137] American Institute of Chemical Engineers, "An Overview of Hydrotreating," Oct. 2021.

refineries, as the majority of refinery hydrogen is purchased from merchant suppliers.[138] The portion of hydrogen from merchant suppliers could in some cases be easier to decarbonize at hydrogen-specific production facilities, rather than needing to overcome space and other constraints by retrofitting within a refinery.

FIGURE 7

Sources of petroleum refining emissions[139]



Refining Decarbonization Methods & Commercialization Pathways

Each refinery is unique, with production varying based on product demand, available on-site space, and integration with transportation and processing infrastructure. This variability makes it difficult to apply a single decarbonization solution across all refineries.

However, refineries are alike in their hydrogen production processes, and transitioning these production pathways to low-carbon alternatives will greatly reduce GHG emissions from the refining sector. Globally, the refining sector consumes 41 MMT of hydrogen annually. According to analysis by CATF, 26 MMT of this can be replaced with low-emissions hydrogen, resulting in an annual reduction of 240 to 380 MMT of CO_2 emissions globally. The remaining 15 MMT of hydrogen is created as a by-product of other refining processes, mainly naphtha reforming, and from petrochemical processes like steam cracking, making it more difficult to simply replace with low-emissions hydrogen.[140] However, other experts assert that by-product hydrogen

[138] WRI, "A Low-Carbon Future in the US Depends on Decarbonizing Petroleum Refineries," Oct. 21, 2021.
[139] WRI, "A Low-Carbon Future in the US Depends on Decarbonizing Petroleum Refineries," Oct. 21, 2021.
[140] Clean Air Task Force, "Hydrogen for Decarbonization: A Realistic Assessment," Nov. 21, 2023.

constitutes a minimal portion of U.S. refineries' hydrogen demand and in terms of logistical feasibility, the majority of the hydrogen used at U.S. refineries could be easily transitioned to low-emissions hydrogen.

Existing Refining Decarbonization Technologies

The hydrogen used in U.S. refineries can be transitioned to hydrogen produced through cleaner methods: either electrolysis paired with clean electricity or SMR or ATR facilities with carbon capture and strict upstream methane leak controls. While barriers to this transition remain—and will be addressed in later sections—there is general agreement from experts that these barriers are more financial and market-based, rather than technical to the refinery sector.

Expected Refining Decarbonization

According to DOE, as of 2023, there were five low-emissions hydrogen projects—exclusive of any hydrogen hub projects—announced in the U.S. that planned to include refining as an end-use. The projects are all fossil SMR with carbon capture, totaling 1.1 MMT of hydrogen production annually.[141] Below are some of these examples of U.S. projects as well as relevant hydrogen hub projects:

- *ExxonMobil Baytown Hydrogen Production Facility*. ExxonMobil is planning a hydrogen production facility in Baytown, Texas that will use natural gas SMR with carbon capture. The facility is expected to produce one billion cubic feet per day of hydrogen, with production commencing in 2027 or 2028 pending final investment decision (FID). The company is aiming to achieve a 98% carbon capture rate. Much of this hydrogen is expected to be used as both a fuel and a feedstock on-site at Exxon's integrated Baytown complex.[142]
- *Gulf Coast Hydrogen Hub*. HyVelocity—an industry group comprised of AES Corporation, Air Liquide, Chevron, ExxonMobil, MHI Hydrogen Infrastructure, and Ørsted—is the prime contractor for the Gulf Coast Hydrogen Hub, a recipient of $1.2 billion through the U.S. DOE's Regional Clean Hydrogen Hubs program. The hub is planning to produce hydrogen through electrolysis and natural gas SMR with carbon capture for refineries—as well as for fuel cell trucks, ammonia production, chemical production, and other industrial processes—in Texas and the broader U.S. Gulf Coast.[143]

[141] U.S. DOE, pg. 24, "Pathways to Commercial Liftoff: Clean Hydrogen," March 2023.
[142] ExxonMobil, "Low-carbon hydrogen: Fueling our Baytown facilities and our net-zero ambition," Jan. 30, 2023.
[143] U.S. DOE, "Gulf Coast Hydrogen Hub," last accessed Mar. 2025.

- *Midwest Hydrogen Hub*. The Midwest Hydrogen Hub is led by a consortium of public and private entities, including BP. The Hub will produce hydrogen from electrolysis and natural gas SMR with carbon capture, to be used in refining as well as steel production, power generation, manufacturing, and heavy-duty transportation. Operations will span Illinois, Indiana, Iowa, and Michigan.[144]

There are other low-emissions hydrogen projects internationally that are focused on the refining sector, including:

- *REFHYNE Project*. Shell is planning to use electrolytic hydrogen for refining operations at its Rheinland Energy and Chemicals Park in Germany. Shell partnered with ITM (an electrolyzer manufacturer) and Linde for this project and received funding from the European Commission's Fuel Cells and Hydrogen Joint Undertaking (now Clean Hydrogen Partnership). The first phase of the project involved installing and operating a 10 MW PEM electrolyzer—the largest PEM electrolyzer in the world—that produces 1,300 tons of hydrogen annually.[145] The second phase of the project, REFHYNE II, involves installing a 100 MW PEM electrolyzer that will produce 44,000 kilograms of hydrogen daily.[146]
- *Total Energies Partnership with Air Liquide and Air Products*. Total Energies, a French multinational integrated oil and gas company, signed offtake agreements with Air Liquide and Air Products for electrolytic hydrogen to use at Total's refineries. The agreement with Air Liquide is for two electrolyzer projects; one is a 250 MW electrolyzer that will supply 30,000 tons of hydrogen annually to the Zeeland refinery (in the Netherlands) and the other is 130 MW (of a 200 MW electrolyzer) for 15,000 tons of hydrogen annually for Total's Antwerp Platform.[147] The 15-year agreement between Total and Air Products is for 70,000 tons of electrolytic hydrogen annually, starting in 2030, to be used at Total's Northern European refineries.[148]

[144] University of Michigan, "Midwest Hydrogen Hub awarded $1B in DOE funding," Nov. 20, 2024.
[145] REFHYNE EU, "About: Project Overview," last acc. March 2025.
[146] Shell, "Media Release: Shell to build 100-megawatt renewable hydrogen electrolyzer in Germany," July 25, 2024.
[147] TotalEnergies, "Media Release: TotalEnergies Joins Forces with Air Liquide to Decarbonize its Refineries in Northern Europe with Green Hydrogen," Feb. 18, 2025.
[148] Air Products, "Media Release: Decarbonization of European Refineries: A first agreement signed between TotalEnergies and Air Products for the delivery of Green Hydrogen," June 7, 2024.

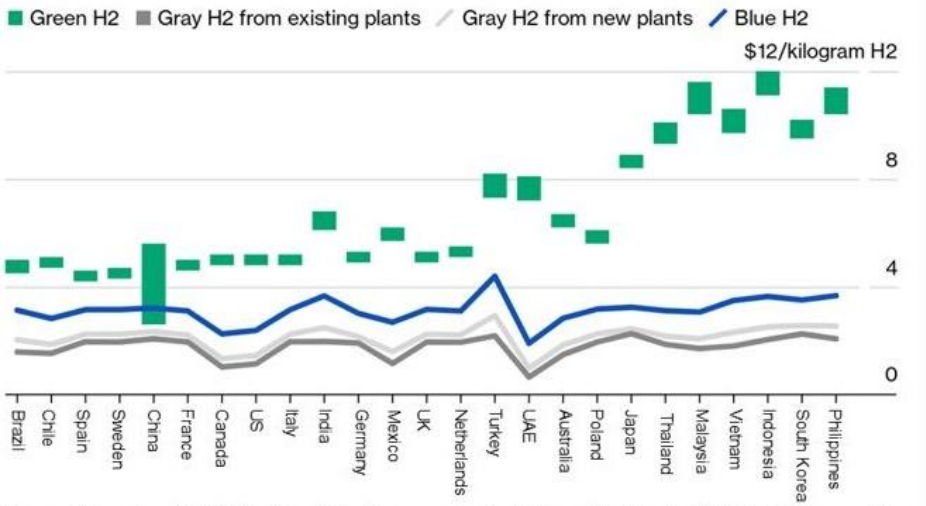
Barriers to Low-Emissions Hydrogen Use for Ammonia and Refineries

Costs

The cost of producing hydrogen in the U.S. changes significantly depending on how it is produced. For example, for 'gray' hydrogen, DOE estimates that the current cost of hydrogen produced from natural gas is $1.1 per kilogram. When combined with carbon capture, the cost increases to $2.1 per kilogram, largely attributable to upfront capital costs of installing CCS equipment (though with some additional ongoing costs to operate such equipment and excluding costs related to transport and storage). Hydrogen produced via electrolysis is the most expensive, with current costs of $5.4 per kilogram and some estimates even higher.[149] These electrolysis costs are currently most attributable to the high upfront costs of purchasing and installing electrolyzers; however, they also require ongoing costs to purchase electricity and maintain equipment.

FIGURE 8

Levelized cost of hydrogen in 2023, by country [150]



Source: BloombergNEF. Note: Blue H2 is the average of auto-thermal reforming (ATR) and steam methane reforming (SMR) production. Green H2 includes Western-made proton-exchange membrane electrolyzers (top of range) and alkaline electrolyzers (bottom of range), except in China, which includes Chinese-made alkaline electrolyzers (bottom of range).

BloombergNEF

The forecasted costs in 2030 for various production methods for low-emissions hydrogen range, as does the projected willingness to pay for hydrogen in both the refining and the ammonia sectors.

[149] These costs do not include the Section 45V or 45Q tax credits. U.S. DOE, pg. 11, "Pathways to Commercial Liftoff: Clean Hydrogen," Dec. 2024.
[150] BNEF, "Green Hydrogen to Undercut Gray Sibling by End of Decade," Aug. 9, 2023.

DOE projects that production costs using reformation (either SMR or ATR) with carbon capture could come down to $1.8 per kilogram in 2030, while electrolysis costs could decrease to $3.2 per kilogram (in both cases, these values are pre-45V or 45Q tax credit application).[151] While that represents a 40% cost reduction for electrolysis, such cost decreases are dependent on availability of clean electricity and decreasing costs of electrolyzers, and further cost decreases will be needed for electrolytic production to economically compete with incumbent production.

Ammonia

While DOE found (as noted previously) that incumbent uses of ammonia could drive near-term uptake of low-emissions ammonia, demand from these incumbent uses is not expected to grow dramatically. Thus, the expected *growth* for low-emissions ammonia production in the coming decades is driven by demand for low-carbon fuels and feedstocks in new sectors and applications. This changes the economic considerations for new facilities and incentivizes prioritizing low-carbon production methods from the start.[152] However, incumbent ammonia producers—particularly for fertilizers—do not face that same external pressure, as demand for low-carbon fertilizer has yet to take off.

Transitioning fertilizers from conventional natural gas-based production to low-emissions production is costly, and there is a low willingness to pay for clean fertilizers. DOE sets the willingness to pay for clean ammonia at $1.50 per kilogram for the fertilizer industry, compared to a willingness to pay at $2 for the steel sector and $4.50 per kilogram (the highest-paying end use) for road transport.[153] Other sources maintain that DOE's projected willingness to pay for the fertilizer industry is high, and in actuality it is even less than $1 per kilogram.[154]

In the U.S., even after considering existing tax credits, ammonia is likely to be more cost-effectively produced via SMR with CCS than electrolysis given the potentially low cost of capturing process emissions from SMR.[155] The cost of abatement for CCS varies, with estimates ranging from approximately $80-$130 per ton of CO_2.[156, 157]

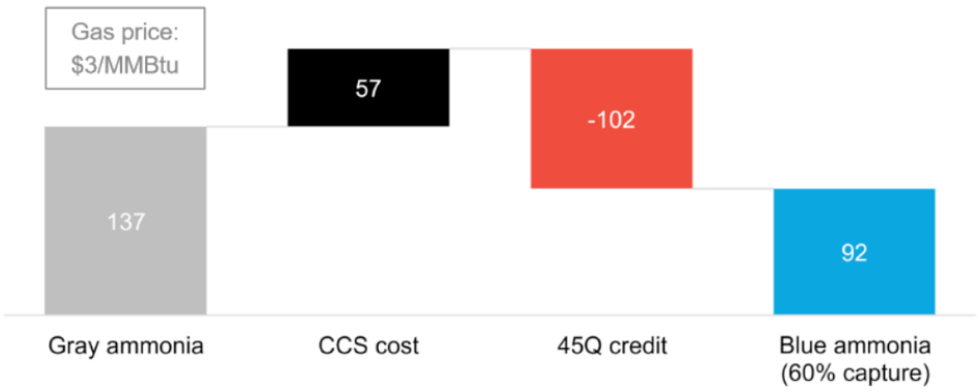
Some—potentially optimistic—analysis shows that the Section 45Q tax credit for carbon sequestration could cover this cost for incumbent ammonia producers, as it provides $85 per ton of CO_2 captured and stored. As the Section 45Q tax credit could be higher than the cost of

[151] U.S. DOE, pg. 11, "Pathways to Commercial Liftoff: Clean Hydrogen," Dec. 2024.
[152] Renewable Thermal Collaborative, "Chemical Sector Decarbonization Roadmap," June 2024.
[153] U.S. DOE, pg. 4, "Pathways to Commercial Liftoff: Clean Hydrogen," March 2023.
[154] Based on expert interviews.
[155] Energy Transitions Commission, pg. 125, "Mission Possible: Reaching Net-Zero Carbon Emissions from Harder-to-Abate Sectors by Mid-Century," Nov. 2018.
[156] Renewable Thermal Collaborative, pg. 29, "Chemical Sector Decarbonization Roadmap," June 2024.
[157] U.S. DOE, pg. 29, "Pathways to Commercial Liftoff: Clean hydrogen," March 2023.

CCS, existing plants that retrofit their production processes with CCS could have a higher profit margin than conventional plants.[158] Most estimates assume that the Section 45Q credit will be slightly more lucrative for hydrogen and ammonia producers using CCS than the Section 45V Clean Hydrogen Production Tax Credit; however, some facilities may select to receive the Section 45V credit instead and would face a similar situation. A select few state-of-the-art 'blue' facilities that utilize extremely high rates of carbon capture (via emergent non-amine based technologies like cryocapture), near-zero methane leak rates, and steam re-use within the facility could potentially receive the highest value of the Section 45V credit. At $3 per kilogram, this would more than subsidize the costs of 'blue' hydrogen and ammonia production.

FIGURE 17

U.S. Ammonia with CCS Cost and 45Q Tax Credit ($ per ton of ammonia)[159]



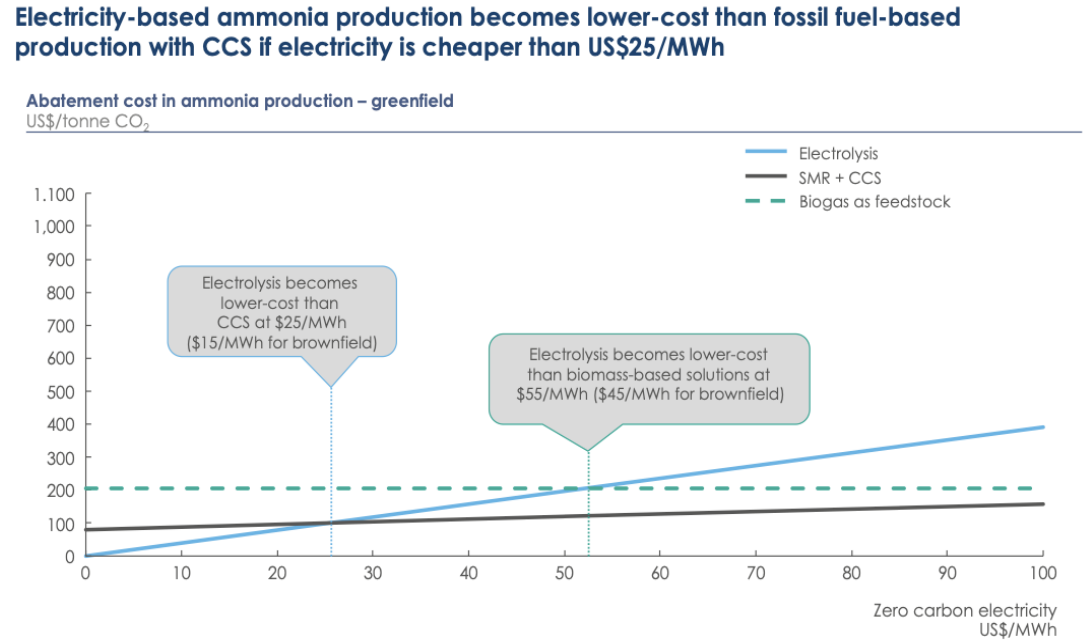
Source: BloombergNEF. Note: Assumes retrofit of existing plant, no ammonia capex expenditure, 32.5 MMBtu of natural gas per ton of ammonia and additional processing costs of $29/ton ammonia and 3.6 MMBtu of gas. Assumes 2 tons CO_2 per ton of ammonia and a 60% capture rate. Carbon capture is assumed to cost $22.3/ton CO_2 and CO_2 transport and storage costs $25/ton CO_2. Uses a 45Q credit of $85/ton CO_2 over 12 years. The CCS capex is assumed to be amortized over the 45Q credit duration.

On the other hand, the exact cost of electrolytic ammonia is dependent on the price of electricity, but even with the Section 45V Clean Hydrogen Production Tax Credit, prices are too high today for electrolytic ammonia to compete with conventional 'gray' ammonia production. Electrolytic production costs need to decrease drastically—some estimates say to $1 per kilogram by 2031—to compete with fossil production.[160] While the Section 45V credit makes this more feasible, many producers may be unwilling to take on the risk of more expensive production without certainty that there will be willingness to pay for their low-carbon product.

[158] BNEF, "Ammonia Supply Outlook 2024: A Clean Takeover," Aug. 8, 2024.
[159] BNEF, "Ammonia Supply Outlook 2024: A Clean Takeover," Aug. 8, 2024.
[160] Renewable Thermal Collaborative, pg. 29, "Chemical Sector Decarbonization Roadmap," June 2024.

FIGURE 9

Cost of Electrolytic Ammonia Production[161]



Source: McKinsey & Company (2018), *Decarbonization of the industrial sectors: the next frontier*

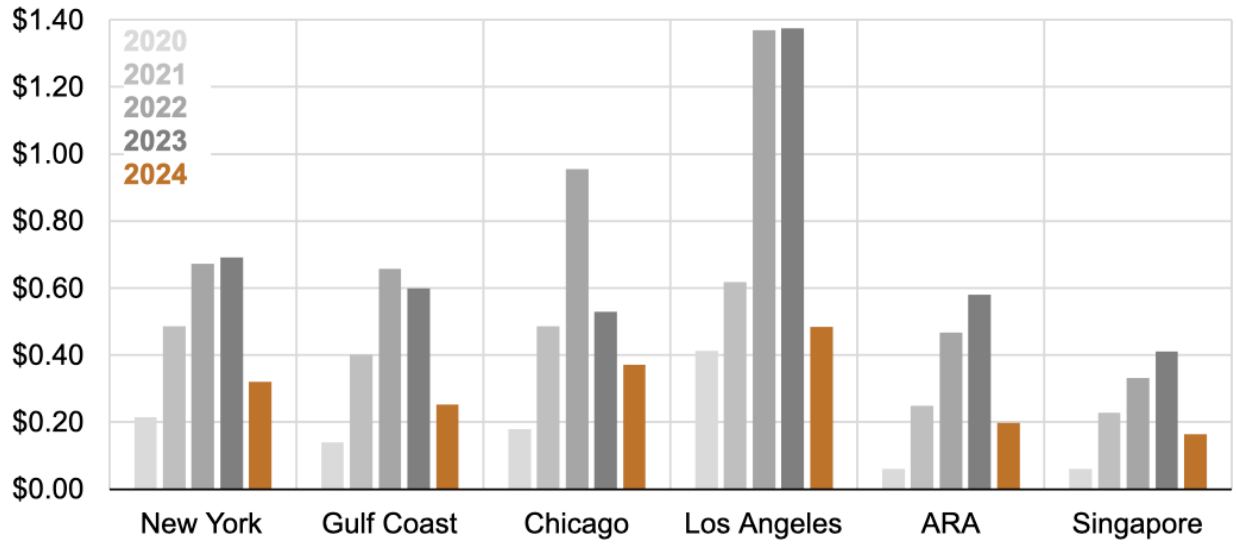
Refining

The refining sector also has low profit margins, which are generally measured by the 3:2:1 crack spread: the difference between the price of three barrels of crude oil, the price of two barrels of gasoline, and one barrel of distillate. In September 2024, profit margins in the U.S. ranged from around 25 cents to 50 cents per gallon.[162]

[161] Energy Transitions Commission, pg. 71, "The Mission Possible: Reaching Net-Zero Carbon Emissions from Harder-to-Abate Sectors by Mid-Century," Nov. 2018.
[162] U.S. EIA, "Global refinery margins fall to multiyear season lows in September," Oct. 15, 2024.

FIGURE 10

Regional September refining margins, in dollars per gallon[163]



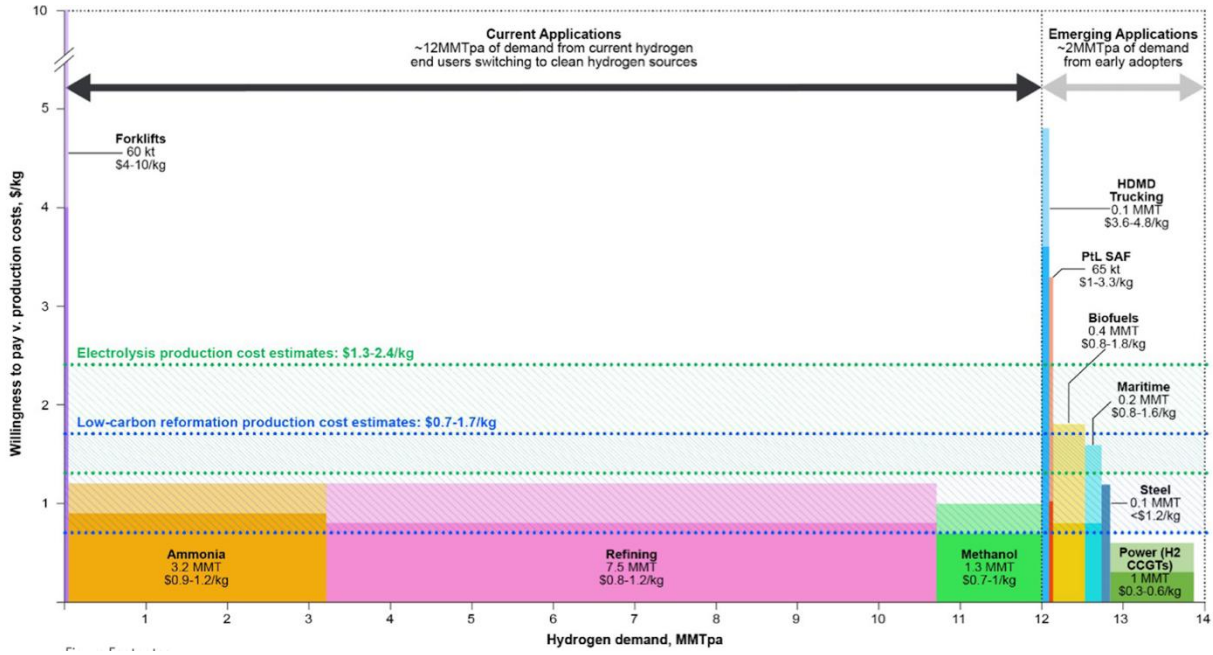
Refining is expected to rely on fossil-based reformation with carbon capture for low-emissions hydrogen in the near term both due to these tight profit margins, its historic knowledge of SMR technology, and its proximity to CCS infrastructure.[164]

DOE estimates that the willingness to pay for hydrogen in the refining sector ranges from $0.8 to $1.2 per kilogram, regardless of how that hydrogen is produced. This could be achievable for SMR with carbon capture or, in select locations, electrolytic hydrogen with government support. The colocation of refineries and hydrogen production facilities further enables the transition, as it limits midstream transportation costs.[165]

[163] U.S. EIA, "Global refinery margins fall to multiyear season lows in September," Oct. 15, 2024.
[164] U.S. DOE, pg. 40, "Pathways to Commercial Liftoff: Decarbonizing Chemicals & Refining," Sept. 2023.
[165] U.S. DOE, pg. 17, "Pathways to Commercial Liftoff: Clean Hydrogen," Dec. 2024.

FIGURE 11

Domestic low-emissions hydrogen demand and willingness to pay vs. production costs, including subsidies, 2030[166]



Timelines

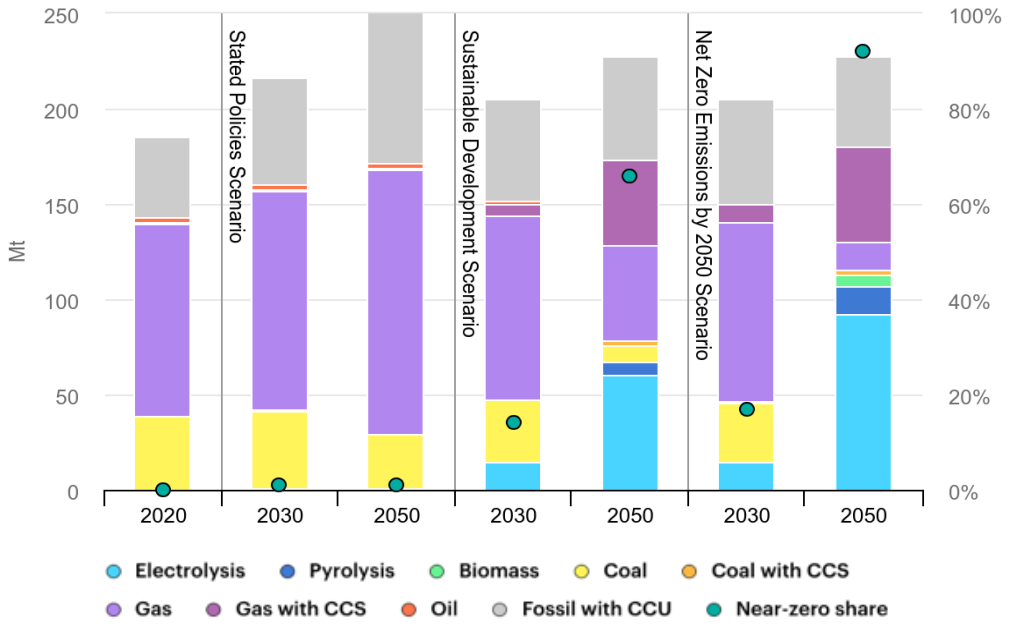
Ammonia

Timelines for ammonia decarbonization vary, but multiple sources project most ammonia production to be decarbonized by 2050. For example, as shown in Figure 21 below, the International Energy Agency (IEA) projects that in a Sustainable Development Scenario and Net-Zero Emissions by 2050 Scenario, ammonia production will consist mostly of electrolysis and fossil-production using CCS. Unfortunately, on the other hand, IEA also found that in a Stated Policies Scenario, a majority of ammonia is still unabated for GHGs by 2050 without additional policy or private sector incentives. Additionally, under both scenarios, there is a heavy reliance on fossil-based hydrogen production with CCS through 2050, which can have economy-wide emissions implications if upstream methane leaks are not appropriately minimized.

[166] U.S. DOE, pg. 20, "Pathways to Commercial Liftoff: Clean Hydrogen," Dec. 2024.

FIGURE 21

Global ammonia production by technology and scenario, 2020-2050 [167]

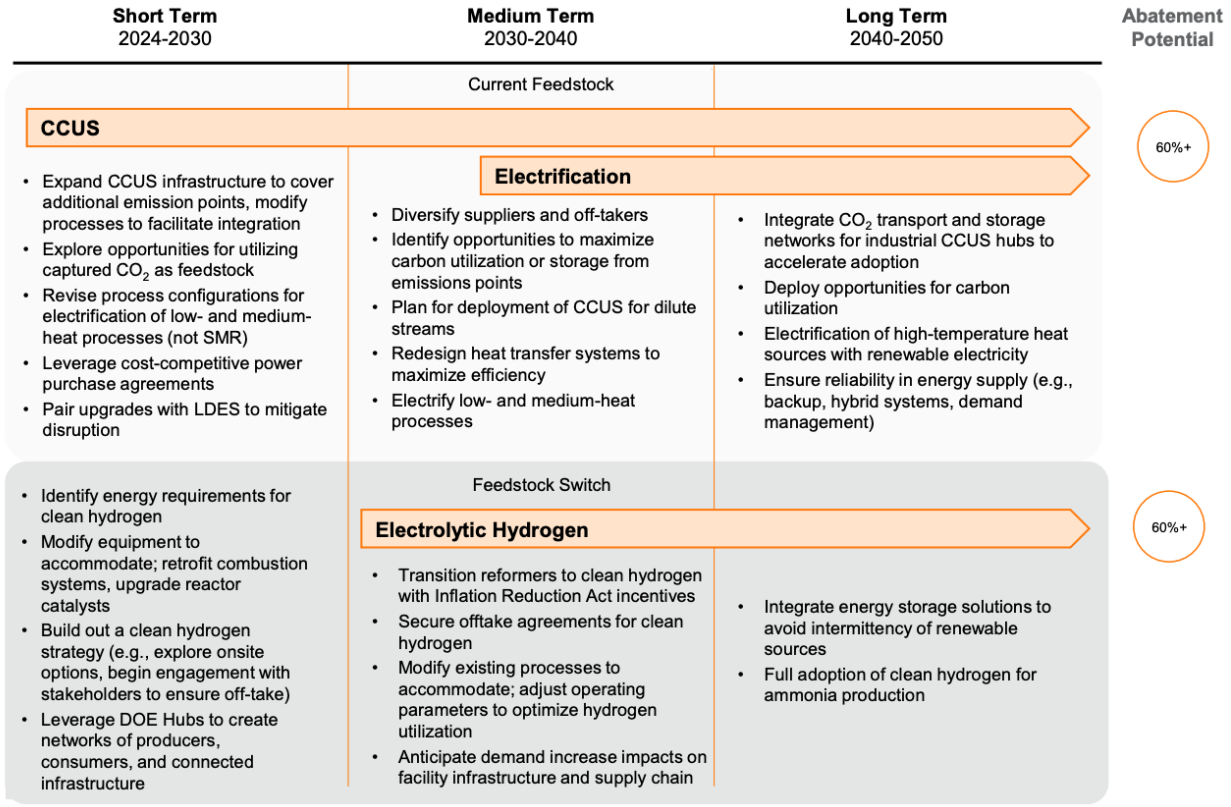


Similarly, the Renewable Thermal Collaborative (RTC) found that ammonia will begin shifting towards natural gas with CCS in the 2020s, followed by a shift towards electrolytic ammonia starting in the 2030s. The RTC provided a roadmap (shown in Figure 22 below) that could aid companies in thinking about what steps to take in shifting towards clean ammonia over the coming decades.

[167] IEA, "Global ammonia production by technology and scenario, 2020-2050", 2021.

FIGURE 22

Timeline & Roadmap for Clean Ammonia[168]

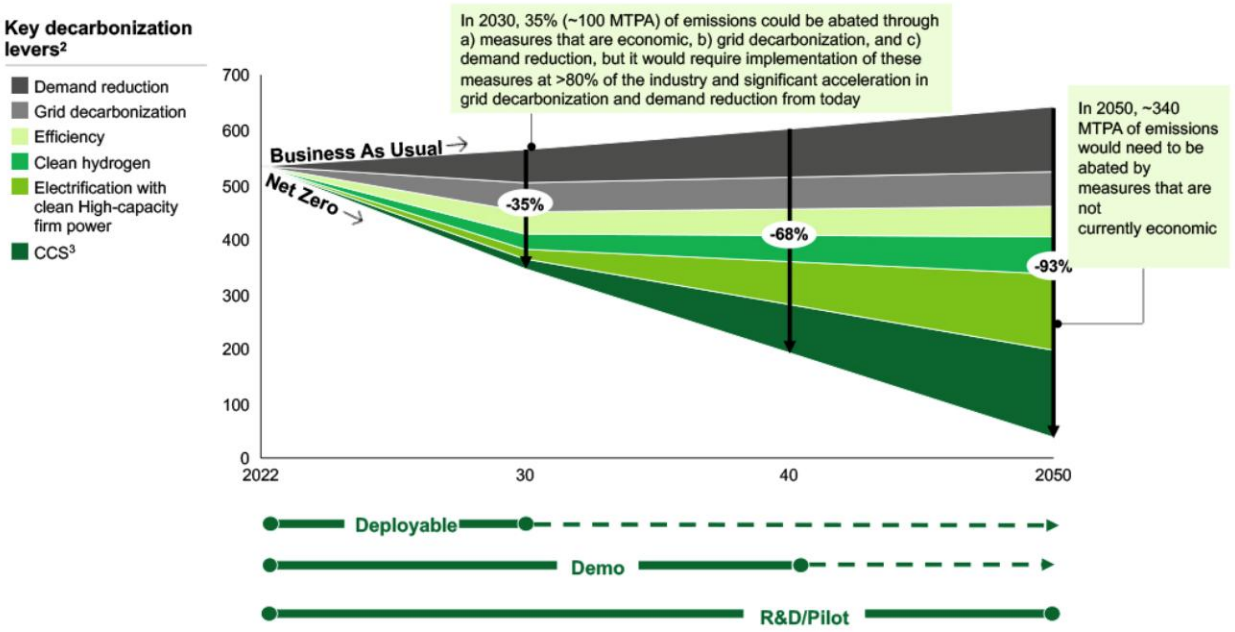


Finally, DOE also found that the chemicals and refining sectors (which includes ammonia production) are unlikely to meet U.S. decarbonization goals without additional ambition and policy.[169]

[168] Renewable Thermal Collaborative, pg. 47, "Chemical Sector Decarbonization Roadmap," June 2024.
[169] U.S. DOE, pg. 3, "Pathways to Commercial Liftoff: Decarbonizing Chemicals & Refining", Sept. 2023.

FIGURE 23

Emissions from Chemicals and Refining (MMT CO_2)[170]



1. Deployable bio-processes that reduce lifecycle emissions of chemicals and refining products are not considered in the pathway to net zero
2. Technologies considered in pathway are in the deployable and demo categories. Pathways may be updated with different developed technologies in future
3. Only CCS is considered in the net zero pathway, refer to Carbon Management Liftoff report for discussion of carbon utilization technologies

Source: EIA data for energy-related emissions, EPA national recycling strategy, White House – The Long-Term Strategy of the United States – Pathways to Net-Zero Greenhouse Gas Emissions by 2050

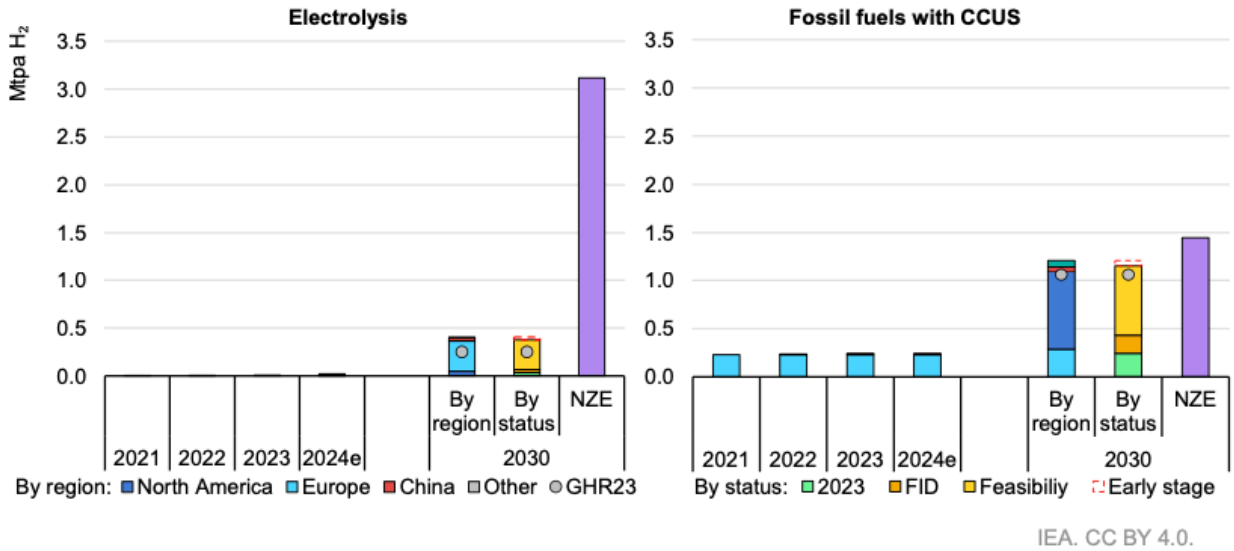
Refining

Timelines for decarbonization of the refining sector vary greatly. IEA's analysis of globally announced projects finds that only 1.6 MMT of low-emissions hydrogen could be produced for oil refineries annually by 2030, which would only meet around one-quarter of the need in a net zero emissions scenario.[171]

[170] U.S. DOE, pg. 3, "Pathways to Commercial Liftoff: Decarbonizing Chemicals & Refining", Sept. 2023.
[171] IEA, pg. 30, "Global Hydrogen Review," Oct. 2024.

FIGURE 24

Global onsite low-emissions hydrogen production at refineries, based on announced projects[172]



Following 2030, IEA projects that refining's demand for hydrogen could decrease as global demand for fossil fuels decreases. IEA forecasts that refineries globally could consume only eight MMT of hydrogen in 2050 compared to 36 MMT in 2020. The agency expects refineries to continue to play a major role in the hydrogen economy though, with 25% of hydrogen production in 2050 occurring at industrial facilities, including refineries.[173]

Projections from DOE are far more optimistic of the uptake of low-emissions hydrogen in the refining sector, at least domestically. According to DOE projections, low-emissions hydrogen could replace current unabated fossil hydrogen in the refining sector by 2030.[174]

Infrastructure Needs

Regardless of production pathway, the production of clean hydrogen will require additional infrastructure buildout. Ammonia production and refining companies will benefit from investing in facility modifications and infrastructure today while exploring sourcing options, like long-term offtake agreements, in preparation for the economic viability of low-emissions hydrogen.[175]

[172] IEA, pg. 31, "Global Hydrogen Review," Oct. 2024.
[173] IEA, pg. 76, "Net Zero by 2050: A Roadmap for the Global Energy Sector," Oct. 2021.
[174] U.S. DOE, pg. 17, "Pathways to Commercial Liftoff: Clean Hydrogen," Dec. 2024. This is based on a willingness to pay of $0.8 to $1.2 per kilogram.
[175] Renewable Thermal Collaborative, pg. 4, "Chemical Sector Decarbonization Roadmap," June 2024.

Electrolytic hydrogen production relies heavily on clean electricity, necessitating that production facilities be located near renewable power sources with reliable grid connections. This dependency can complicate efforts to repurpose or decommission existing infrastructure. [176]

Similarly, hydrogen production utilizing CCS will require substantial infrastructure, including systems for capturing, transporting, and storing carbon–all of which must be built and operated to ensure safety and environmental integrity as incidents on either front would compromise both carbon intensity claims as well as public and investor confidence. Although captured carbon can be transported by truck, pipelines are generally more cost-effective, and adequate storage infrastructure must also be established. Current CCS facilities face the challenge of a lack of CO_2 transportation and storage infrastructure, as this is dependent on the sufficiency of nearby geological storage sites (which vary by region).[177] Additionally, any new hydrogen facilities or retrofits to facilities that use fossil-based SMR production should be built with CCS-readiness in mind (for example, allotting the necessary physical space for capture equipment) even if CCS will not be installed immediately.

Storage infrastructure buildout can be mitigated if utilization of CO_2 increases, but companies have faced challenges securing offtakers, and the climate benefits decrease in comparison to permanent sequestration, which may have implications for carbon intensity claims. There are many potential applications for CO_2—such as in the food and beverage and chemicals industries—but selling it necessitates additional costs for separating and transporting it. Of the 55 refineries with onsite SMRs in 2018, only 12 exported CO_2 to a customer.[178]

As with all industrial and major infrastructure projects, deployment of CCS infrastructure will require consideration of community engagement and social acceptance. Effective engagement can provide communities with necessary project information and a pathway to providing input on specific projects, while local acceptance can influence permitting processes and project timelines for developers. Establishing community benefit frameworks—with possible benefits such as local employment opportunities, infrastructure investments, or other economic considerations—can provide an avenue for host communities and developers to come to agreement on the distribution of project costs and benefits. While not the focus of this report (which centers on technical and economic constraints), these issues should be considered for future analysis.

[176] Renewable Thermal Collaborative, pg. 29, "Chemical Sector Decarbonization Roadmap," June 2024.
[177] Renewable Thermal Collaborative, pg. 29, "Chemical Sector Decarbonization Roadmap," June 2024.
[178] WRI, pg. 9, "Technological Pathways for Decarbonizing Petroleum Refining," Sept. 2021.

Ammonia

The on-farm transition to cleaner fertilizer is simplified by the fact that low-carbon ammonia is the same final product as conventional ammonia, thus not requiring any on-farm transition in fertilizer practices. This is notably not the case for other potential end-uses of clean ammonia, such as in marine shipping, where new equipment and technology is needed. This consistency provides an advantage to incumbent users and allows farmers to use existing infrastructure and equipment.

The development of a market specifically for low-carbon ammonia could still necessitate infrastructure buildout, as ammonia production on a large scale at low cost is possible in favorable locations and could then be traded internationally. An increase in international trade of clean ammonia would likely involve new shipping models similar to liquefied natural gas or long-distance pipelines, requiring adaptations to port infrastructure. For example, several transportation solutions are being tested between Australia and Japan.[179]

Domestically, ammonia is typically transported by short pipelines, trucks, or specialized railcars. Due to a limited number of domestic producers, long-haul shipment of anhydrous ammonia is often accomplished via rail.[180] Increased demand for ammonia will also require buildout of this transportation infrastructure.

Ammonia is currently listed on the Toxic Substances Control Act (TSCA) Chemical Substance Inventory which contains all existing chemical substances manufactured (including imported) or processed in the U.S.[181] Expanded use of ammonia would require attention to safety protocols, though as previously mentioned, use of low-carbon ammonia is the same product as conventional ammonia and would require similar risk management.

Refining

While refineries can benefit from extensive existing infrastructure, particularly in regions such as the U.S. Gulf Coast, refineries that do not produce their own hydrogen onsite will also have to contend with the infrastructure challenges in producing, transporting, and storing low-emissions hydrogen at scale. In addition, physical space can be a limitation at existing refineries, making it challenging to install new hydrogen storage tanks, renewable energy, electrolyzer stacks, or carbon capture, storage and transport infrastructure. Refineries also often must operate their equipment 24/7, making it challenging to accommodate the production of 'green'

[179] Energy Transitions Commission, pg. 160, "The Mission Possible: Reaching Net-Zero Carbon Emissions from Harder-to-Abate Sectors by Mid-Century," Nov. 2018.
[180] U.S. EPA, "Anhydrous Ammonia Supply Chain," Dec. 2022.
[181] U.S. EPA, "TSCA Chemical Substance Inventory," April 2025.

hydrogen during only times with available intermittent clean electricity without purchase of high-integrity renewable electricity credits. Finally, many refineries in the U.S. are aging, and thus may be more difficult to retrofit compared to newer refineries.

Policy Frameworks for Maximizing Climate Benefits from Low-Emissions Hydrogen

This section discusses policy and market approaches to enable use of low-emissions hydrogen in the end-use sectors with the most climate benefit. The policy solutions that we recommend are based on either: (1) directing low-emissions hydrogen supply to the sectors discussed in this report; (2) addressing sector-specific barriers to adopting low-emissions hydrogen, or (3) addressing broader system-wide barriers. Additionally, for the vast majority of the recommendations outlined in this section, the policies would benefit from strong guardrails and monitoring, verification, and enforcement mechanisms. These guardrail provisions could help ensure that the hydrogen stakeholders benefitting from such policies are producing truly low-emissions hydrogen based on rigorous full lifecycle emissions analyses, using it effectively to maximize climate benefits and minimize environmental and other impacts, and building infrastructure to avoid hydrogen leakage.

Finally, it is worth noting that the decarbonization technology and large infrastructure needed for projects such as low-emissions hydrogen production and/or CCS can be complex to implement. Additional factors to consider include local pollution impacts, environmental justice, and meaningful community engagement in siting and permitting. These considerations are vital to the durability and success of decarbonization strategies and warrant their own deep dive for technical and policy considerations. However, these are beyond the scope of this paper and are a limitation to consider in the recommendations below.

TABLE 2

Comprehensive List of Potential Solutions

Barriers	Proposed Solution(s)	Jurisdiction
Recommendations to Direct Low-Emissions Hydrogen Supply to Key End-Use Sectors		
Climate benefit is not correlated to cost, ease of transition, or willingness to use and pay for low-emissions hydrogen.	Differentiated end-use sector support (e.g., end-use tax credits).	State
	Focusing of DOE $1B for demand-side initiatives in hydrogen hubs on climate-beneficial end-users.	Federal

There are currently no regulations or market-system to ensure hydrogen is not wasted in sectors where it provides little to no benefit.	Rescission of any existing policy support for using hydrogen in light-duty vehicles and blending into the gas grid.	Federal & State
	Regulations to limit use of hydrogen in non-beneficial end-use sectors.	Federal & State
	Use of appropriations report language and budget priorities to direct funding to priority end-uses.	Federal & State
Recommendations to Address Ammonia-Specific Barriers		
Significant cost differential remains between conventional and low-emissions ammonia.	Tax credits or contracts for differences directed to the ammonia producer to cover any differential in the cost of producing low-emissions ammonia that is required to reach parity when combined with other policy support.	State
	Decentralized clean fertilizer production methods and business models.	Market
Fertilizer consumers (i.e. farmers) have low margins of profit and thus a very limited willingness to pay for any green premium on fertilizer products.	Tax credit or grants directed to farmers specifically for purchase of low-carbon ammonia-based fertilizers.	Federal & State
	Buyers' alliance and demand aggregation.	Market
	Market shift towards long-term offtake agreements to give producers certainty that they will have a customer able to pay a certain price.	Market
Recommendations to Address Refinery-Specific Barriers		
The refinery products market values maximizing profits and does not internalize costs of clean production.	Product standards, agreed to by industry or instituted by government, on carbon intensity of refinery products.	Market & Federal
	Low-carbon fuel standard or other clean fuel standard.	State
	Market-based disclosure requirement system for carbon intensity from hydrogen producers.	Market
Costs of low-emissions hydrogen remain notably higher than conventional hydrogen, and refineries operate in a competitive market with low willingness to pay.	Financial instruments (e.g., tax credits, low- or no-interest loans, and contracts for differences) to incentivize production or purchase of low-emissions hydrogen.	Federal & State
	Distribution of costs of decarbonizing refinery products across value chain, through buyers' alliance, long-term offtake agreements, or credit systems for low-emissions hydrogen.	Market
Recommendations to Address System-Wide Barriers		
GHG emission reductions are not appropriately priced into private sector decision-making on effective use of decarbonization resources.	Domestic carbon fee (particularly for the industrial, transportation, and power sectors) and/or statewide GHG emission caps or carbon markets.	Federal & State
U.S. electricity grid lacks transmission capacity to meet demand as additional sectors electrify.	Incentives for new/upgraded transmission lines and grid modernization technologies.	Federal
	Permitting reform to ease process for new transmission lines to enable additional renewables on the system.	Federal & State

Insufficient clean electricity to enable a clean grid and production of green hydrogen/ammonia.	Maintenance of all existing clean electricity incentives and expansion of incentives at the state-level for production of clean electricity.	Federal & State
Low-emissions hydrogen/ammonia lack certification systems to track and purchase clean characteristics untethered from the physical product.	A book & claim system based on a broadly accepted certification system for low-emissions hydrogen/ammonia which requires full lifecycle GHG analysis based on verifiable project- and facility-level information.	Market
Hydrogen and ammonia are international markets, but various countries and regions have mismatched policy requirements for clean production and use.	Alignment of U.S. policy for low-emissions hydrogen/ammonia with international standards.	Federal

Policy Solutions to Direct Low-Emissions Hydrogen Supply to Key End-Use Sectors

Some policies—both "carrots" and "sticks"—can be used to make sure that low-emissions hydrogen is used by specific consumers. These policies would help ensure that use of low-emissions hydrogen can maximize potential emissions reductions in the U.S., rather than being used in sectors or end-uses where it is economically and technologically inefficient. The barriers and policy solutions below address these concerns through frameworks like economic incentives to the desired end-uses, regulations based on carbon intensity of products, and carbon pricing. In addition, some hydrogen projections show less drastic growth rates in hydrogen demand and use, potentially reflecting a more realistic growth rate for the coming years—for example, the IEA cites "unclear demand signals, financing hurdles, delays to incentives, regulatory uncertainties, licensing and permitting issues and operational challenges" as reasons that several planned hydrogen projects have been delayed or cancelled.[182] This potentially more realistic rate of growth in the low-emissions hydrogen sector could help to dissuade ineffective sectors from designing their decarbonization plans around what was previously a massive expected growth in low-emissions hydrogen supply and infrastructure.

Barrier: The climate benefit of using low-emissions hydrogen in a given end-use sector is not correlated to the cost, ease of transition, or willingness to use and pay for low-emissions hydrogen.

> → Policy Solution: Provide differentiated end-use sector support based on the climate benefit of that sector. This could include new state-level end-use tax credits directed to

[182] IEA, "Global Hydrogen Review 2024: Executive Summary", October 2024.

the hydrogen consumer that follow a formula based on climate benefit (e.g., $0/kg for use in the power sector or light-duty vehicles; $0.50/kg for use in medium- and heavy-duty mobility applications and medium- and high-temperature industrial heat processes; and $1/kg for use as a feedstock in fertilizers or refineries). For an example, see the Policy Case Studies section for detail on Colorado's existing hydrogen end-use credit. State-level policies could be most impactful in regions of the U.S. that are developing low-emissions hydrogen hubs or have a relatively greater amount of planned low-emission hydrogen development.

→ Policy Solution: Provide a formulaic approach based on end-use for government support through any grant or loan funding at the state or federal level. A formula could be implemented for any program, such as: direct one half of available funding to decarbonizing existing uses of hydrogen and ammonia (i.e., fertilizers and refineries); one third to medium- and heavy-duty transportation uses and/or medium- and high-temperature industrial heat; and the remaining one sixth to any other end-uses. Dependent upon ongoing changing federal government priorities, this formula could be implemented for the $1 billion in DOE funding for demand-side support in hydrogen hubs for end-use sectors with the most climate benefit. Alternatively, a less formulaic approach could be to include the climate benefit of the end-use sector (particularly for the incumbent hydrogen uses that have no decarbonization alternatives) as a key factor in decision-making, weighed equally to any other factors (such as amount of funding needed to move a project forward).

Barrier: There are limited U.S. regulations applicable to the hydrogen industry, and there is no policy or market-system in place to ensure that it is not wasted in sectors where it provides little to no benefit.

→ Policy Solution: Rescinding of public subsidies for low-emissions hydrogen used specifically in light-duty vehicles or blending into the natural gas grid—the two potential hydrogen end-use sectors with the least climate benefit. While this could have the potential unintended consequence of slowing growth in low-emissions hydrogen production, as the power sector in particular has been touted as an easy early offtaker to provide some certainty to producers, blending small amounts of hydrogen into the natural gas grid as has been proposed makes little financial or climate sense.[183] Similarly, light duty vehicles can be easily electrified and are inefficient users of low-emissions

[183] Clean Air Task Force. *Hydrogen Blending – Not a Serious Decarbonization Pathway*. May 2023.

hydrogen. Rescinding credits for low-emissions hydrogen use in the power sector, particularly in cases where hydrogen is not being used as a means of storing electricity, would also help direct short-term low-emissions hydrogen supply to the incumbent industries (ammonia for fertilizers and refineries) as they are able to use low-emissions hydrogen in their systems immediately.

→ Policy Solution: Regulations to limit use of low-emissions hydrogen in non-beneficial end-uses. At the federal-level, this may need Congressional action to provide the U.S. Environmental Protection Agency (EPA) with this authority. Thus, in the near-term, it may be more productive to explore potential regulations at the state-level, depending on any existing regulatory authority and the potential interest from state agencies and legislatures. Regulations could function through discouraging non climate-beneficial offtake sectors by requiring a technology-neutral full GHG lifecycle assessment, from production through end-use, to determine the emissions reductions of low-emissions hydrogen. A Public Utility Commission (PUC) could then require any proposal to be evaluated based on its lifecycle GHG assessment.

→ Policy Solution: Use federal and state budget appropriations processes (e.g., specific federal agency report language) to require that agencies direct grant funding toward hydrogen in incumbent and climate-beneficial end-uses.

Policy Solutions to Address Ammonia-Specific Barriers

This section includes policy proposals intended to target the specific challenges encountered when transitioning to low-emissions hydrogen in the ammonia fertilizer market. These include concerns around the cost of low-emissions hydrogen as well as lack of demand for low-carbon fertilizers from fertilizer consumers.

Barrier: A significant cost differential remains between the production of conventional ammonia and the production of clean ammonia. While this differential is smaller for 'blue' ammonia production (with the Section 45Q credit), it is still quite large for 'green' ammonia (even with the Section 45V credit).

→ Policy Solution: Tax credits or contracts for differences directed to the ammonia producer (i.e., the low-emissions hydrogen end-user) to cover any differential in the cost of producing 'green' ammonia that is required to reach parity (when combined with the Section 45V credit, which is instead directed to the low-emissions hydrogen producer). According to DOE, at today's costs of production, conventional hydrogen costs $1.10 per kilogram, 'blue' hydrogen costs $2.10 per kilogram, and 'green' hydrogen costs $5.40 per

kilogram to produce.[184] With the Section 45Q or 45V credits at about $1 per kilogram for 'blue' hydrogen, the cost of producing 'blue' hydrogen is already around parity with conventional hydrogen. However, even with the full Section 45V credit of $3 per kilogram for 'green' hydrogen, the cost of producing 'green' hydrogen is $2.40 per kilogram compared to conventional hydrogen's $1.10. A tax credit for the ammonia producer of an additional $1.00 - 1.50 per kilogram could bring 'green' ammonia in line with costs of conventional production. This end-use credit could also be technology-neutral if it is based on tons of CO_2e reduced per year and provided to the ammonia producer for any clean fuel or decarbonization method used for production of fertilizer.

→ Policy Solution: Encourage decentralized clean fertilizer production models. Distributed production of clean ammonia can make clean fertilizer more accessible to farmers and insulate the fertilizer consumers from infrastructure challenges, price shocks, and competition. For example, the agriculture solutions provider Landus and the green ammonia producer Talus Renewables are partnering to provide farmers with a modular, easily installable onsite green fertilizer production system.[185] Their system incorporates onsite renewables, flexible electrolyzers that can align with intermittent energy sources, and the Haber-Bosch process to convert the green hydrogen into anhydrous ammonia. Policies at the federal-level (e.g., utilizing existing programs at the U.S. Department of Agriculture) or state-level can provide upfront funding or low- or no-interest loans for farmers to install such equipment. A program and model of this type can also help minimize risk for farmers and provide them with more control of their long-term costs, so they are not at the whims of any price volatility in the fertilizer market.

Barrier: Fertilizer consumers (i.e. farmers) have low margins of profit and thus a very limited willingness to pay for any green premium on fertilizer products. In addition, there is high sensitivity to changes in food prices, and thus reluctance to increase supply chain costs.

→ Policy Solution: Tax credit or grants directed to farmers specifically for purchase of low-carbon ammonia-based fertilizers. A credit of about $1.00 to $2.00 per kilogram of clean ammonia could bring fertilizer customers in line with the costs of producing 'green' ammonia, as well as making them more competitive with other industries competing for the clean ammonia. Alternatively, to make funding more accessible to farmers without

[184] These costs do not include the Section 45V or 45Q tax credits. U.S. DOE, pg. 11, "Pathways to Commercial Liftoff: Clean Hydrogen," Dec. 2024.
[185] Landus Agriculture, "Green Ammonia", last accessed Mar. 10, 2025.

requiring tax burden, the tax credit or grants could be directed to the middle-men distribution companies that typically buy and sell fertilizer products, with a requirement that a majority of subsidized prices must be passed on to the final consumer of their low-carbon fertilizer.

→ Policy Solution: Buyers' alliance and demand aggregation. A buyers' alliance could bring together demand for low-carbon products that is further up the supply chain than the farmers (e.g., food production companies, distributors such as Whole Foods, Walmart, etc.). The buyers' alliance could purchase the low-carbon fertilizer credits to claim the climate benefit, which would help bring prices of low-carbon fertilizer down for consumers of the physical product. An organized buyers' alliance can also help to educate consumers on the importance of decarbonized products and their impact on consumer goods.

→ Policy Solution: Encourage a market shift towards long-term offtake agreements to give producers certainty that they will have a customer able to pay a certain price. Long-term agreements may mean that producers are willing to accept a slightly lower price in exchange for certainty, and they could also help establish fertilizers as a stable offtake option. For the fertilizer market, entering long-term offtake agreements in the near-term can help insulate them from price increases from global market shifts or additional competition for clean ammonia in the medium-term. State and regional governments and private sector associations can share educational resources and create opportunities for producers and offtakers to network and develop relationships to support creation of longer-term offtake contracts. Policymakers can also integrate a requirement for long-term offtake agreements into other potential policies (e.g., tax credits, contracts for differences, etc.). Finally, a government entity could provide a risk backstop to encourage long-term offtake agreements by mitigating the risk of technology challenges, significant increases in feedstock prices, or other unexpected challenges that could arise in a long-term agreement.

Policy Solutions to Address Refinery-Specific Barriers

This section includes policy proposals intended to target the specific challenges encountered when transitioning to low-emissions hydrogen at refineries. Similar to the ammonia for fertilizer market, refineries face different challenges depending on whether they produce hydrogen themselves onsite or purchase hydrogen from a merchant supplier. The concerns and policy

solutions included in this section address the high costs of decarbonizing and the lack of organized demand for low-carbon refinery products.

Barrier: The market for refinery products values maximizing profits, not maximizing climate benefits. The market needs to shift so that the norm that consumers are used to includes the cost of paying for clean production.

> → Policy Solution: Establish product standards, either agreed to by a large subset of industry players or set by the state or federal government, based on GHG intensity of refinery products. Product standards would ensure that all producers are competing on similar grounds, and decarbonizing the supply chain of refinery products would not affect a company's competitive advantage. These standards would function similarly to requirements for limiting sulfur content in diesel fuels. These emissions product standards could function as a ledger that shows any increases or decreases in CO_2e emissions by the time the product was sold. Relatedly, a government- or market-based system could require disclosures of carbon intensity from hydrogen producers, to enable end-users of hydrogen to better track the environmental attributes. These disclosures would then allow refineries to better track the lifecycle GHG intensity of their refinery products, which can enable more informed decisions and allow future policy to be even more tailored to lifecycle GHG emissions.
>
> → Policy Solution: Low-carbon fuel standard or other clean fuel standard. A clean fuel standard, such as California's Low-Carbon Fuel Standard, can function as the simplest signal for refineries to decrease the carbon intensity of refinery products over time. Low carbon fuel standards have been shown to function well at the state-, regional-, or national-level, and pairing the requirement to decarbonize with the monetization of credits for doing so (and surpassing the requirement) could increase the willingness to pay for low-emissions hydrogen at refineries. To incentivize clean hydrogen's use in refineries, a clean fuel standard must require full lifecycle analysis of the GHG emissions from fuels, such that a gasoline or diesel produced using clean hydrogen would receive a lower carbon intensity than one produced using conventional hydrogen production methods.

Barrier: Refineries operate in a competitive market and have low willingness to pay for decarbonization solutions, such as low-emissions hydrogen, that are not required of them by either regulation or their consumers. Even with subsidies, as explained above, the costs of

producing and purchasing low-emissions hydrogen (particularly 'green' hydrogen) remain notably higher than the cost of conventional hydrogen.

→ Policy Solution: Financial instruments, including tax credits, low- or no-interest loans, and contracts for differences, can be utilized at the state- or federal-level and be directed toward the refinery user to support production or purchasing of low-emissions hydrogen. As noted above, a tax credit of about $1.00 to $1.50 per kilogram directed at the refinery end-user could bring costs of producing or purchasing 'green' hydrogen in line with conventional costs. Grants or loans could be directed toward installation of CCS equipment, upstream methane monitoring equipment and systems, or installation of electrolyzers, for example.

→ Policy Solution: Shift the market for refinery products so that the cost of decarbonizing is more effectively shared across the entire supply chain. This shared cost could occur through market-based systems such as a low-carbon refinery products Buyers' Alliance, procurement or long-term offtake agreements, or a credit system for low-emissions hydrogen, all of which could target large corporate offtakers of refinery products.

Policy Solutions to Address System-Wide Barriers

The final policy solutions section addresses economy-wide challenges that must be addressed through broader solutions than specific hydrogen policies. These include carbon pricing, market creation, transmission capacity, and availability of clean energy.

Barrier: GHG emission reductions are not appropriately priced into private sector decision-making on the most effective use of decarbonization resources.

→ Policy Solution: Institute a domestic carbon fee (i.e. carbon pricing), either economy-wide or for specific sectors. The most impactful sectors to cover for directing low-emissions hydrogen to the appropriate end-uses include the industrial, transportation, and power sectors. Similarly, expand state-level cap and trade emissions programs or other economy-wide emissions regulations at the state- or regional-level. The emissions covered by these regulations can be expanded both by advocating for new programs in new states and by encouraging states with existing programs (such as California, Washington, Oregon, and the Regional Greenhouse Gas Initiative (RGGI) states in the Northeast) to strengthen the stringency of their programs and ensure that hydrogen producers and users are covered.

Barrier: The U.S. electricity grid currently lacks the transmission capacity (both in terms of quantity and location) needed to meet increased demand as additional sectors electrify and more data centers come online.

→ Policy Solution: Implement a federal or regional incentive to encourage construction of new transmission lines and implementation of grid modernization technologies without pushing costs on to electricity consumers.

→ Policy Solution: Conduct permitting reform (at the federal- or state-level) to ease the process for new transmission lines to be built to enable the broader system to take advantage of regions with significant potential renewable resources and to allow for production of 'green' hydrogen and ammonia to connect directly to such renewables.

Barrier: There is currently insufficient clean electricity to enable a clean grid and production of 'green' hydrogen/ammonia.

→ Policy Solution: Maintain all existing clean electricity incentives and expand incentives at the state-level for production of clean electricity. Dependent upon further analysis on the benefit of "stacking" of various incentives, consider allowing low-emissions hydrogen/ammonia incentives to be "stacked" with clean electricity incentives. Require three-pillars to be met for 'green' hydrogen/ammonia production to increase the likelihood that additional clean electricity is being built to meet demand.

Barrier: Low-emissions hydrogen and clean ammonia lack certification systems that would allow for tracking and purchasing of clean characteristics untethered from the physical product itself.

→ Policy Solution: Consider establishing a book and claim system or credit market to allow entities with willingness to pay to purchase the environmental attributes of low-emissions hydrogen to do so, while supporting the use of hydrogen in necessary sectors. As a prerequisite, this includes developing (or supporting existing development of) a broadly accepted certification system for low-emissions hydrogen and clean ammonia which requires full lifecycle GHG analysis based on project- and facility-level information. Organizations conducting early phases of such work (i.e., developing and standardizing the lifecycle emissions accounting methodology) include the Ammonia Energy Association (AEA), the Open Hydrogen Initiative (OHI), and the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE). At a minimum, a low-emissions hydrogen and ammonia certification system would allow for improved

management and tracking of the climate impact of low-emissions hydrogen development and deployment.

Barrier: Hydrogen and ammonia are international markets, but various countries and regions have mismatched policy requirements for clean production and use. In particular, some countries (including the European Union (EU)) have more stringent emissions regulations for production and use of hydrogen, making competition from U.S. exports challenging.

→ Policy Solution: Align U.S. policy for low-emissions hydrogen and ammonia with international standards (e.g., the EU) whenever possible to allow U.S. producers to compete with low-carbon products internationally. Encourage domestic low-emissions hydrogen and ammonia producers to build their infrastructure with a longer-term outlook that considers potential future emissions regulations in the U.S. and existing regulations elsewhere.

Existing Policy Case Studies

This final section provides case studies of two relevant policy examples: a financial instrument in the form of an auction in Europe and three U.S. states with hydrogen end-use tax credit policies.

Contracts for Difference Case Study: H2Global and European Hydrogen Bank

The European Commission established the European Hydrogen Bank in 2022 to scale-up hydrogen production in the EU. The European Hydrogen Bank is tasked with de-risking investment in low-emissions hydrogen, attracting low-emissions hydrogen imports to the EU, and increasing market transparency, among other objectives.[186] The European Hydrogen Bank primarily achieves these through hydrogen auctions that are administered by the H2Global Foundation.

The H2Global Foundation utilizes a tender system, the H2Global Mechanism, to connect buyers and sellers in emerging hydrogen markets through a double-auction system facilitated by an intermediary, Hintco. Low-emissions hydrogen buyers submit the highest price they are willing to pay, and sellers submit the lowest price point they are willing to accept. Hintco pairs respective buyers and sellers and covers the resulting price gap with public and private funding.[187] Public funding is provided by the Innovation Fund, the EU's primary climate policy initiative, which is financed through the EU's carbon pricing system.[188]

[186] The European Commissions, "European Hydrogen Bank," last accessed March 2025.
[187] The H2Global Foundation, "The H2Global Mechanism," last accessed March 2025.
[188] The European Commission, "What is the Innovation Fund?" last accessed March 2025.

The design of the H2Global Mechanism offers a suite of benefits. First, it covers the full hydrogen value chain from production to consumption, supporting greater market buildout. It simultaneously promotes liquidity and ensures bankability, as one-year contracts for sellers allow for market adjustments while 10-year fixed price contracts grant security to producers. While grants and loans have the risk of stranded assets, the H2Global Mechanism minimizes that risk by connecting public funding to product delivery rather than infrastructure buildout. It also offers insight into the developing hydrogen market through continuous price discovery for both producers and consumers.[189]

The H2Global Mechanism can be implemented at both the national and international level and tailored to prioritize specific end-use applications. For example, it could be implemented in the U.S. and target incumbent hydrogen usage in the ammonia and refining sectors.

H2Global has conducted two hydrogen auctions in Europe. Seven projects—out of 132 bids—were selected during the first auction in April 2024.[190] One selected project, the Grey2Green II project, will develop a 200 MW electrolyzer to transition the Galp Energia Group's Sines refinery in Portugal from hydrogen made from a fossil-based SMR to electrolytic hydrogen. The electrolytic hydrogen will replace more than 30% of the refinery's current hydrogen demand.[191] Another selected project, the Catalina project, will develop a 500 MW electrolyzer in Spain that will produce 480,000 tons of low-emissions hydrogen in its first 10 years of operation. The hydrogen will be used to produce ammonia for fertilizer.[192]

Tax Credits Case Study: U.S. State Policies

At least three states in the U.S. currently provide tax credits for low-emissions hydrogen, either based on its production or procurement. These policies are detailed in Table 3, below.

TABLE 3

STATE-LEVEL HYDROGEN TAX CREDITS

	Colorado[193]	**Illinois[194]**	**Pennsylvania[195]**
Requirements for	Hydrogen must have a carbon intensity below 1.5 kg CO_2e per kg of hydrogen	Hydrogen must have a carbon intensity below 0.45 kg CO_2e per kg of	Qualifying hydrogen must be produced at one of U.S.

[189] The H2Global Foundation, "The H2Global Mechanism," last accessed March 2025.
[190] The European Commission, "Winners of the first EU-wide renewable hydrogen auction sign grant agreements," Oct. 7, 2024.
[191] The European Commission, "Project Factsheet: Grey2Green-II," March 2025.
[192] The European Commission, "Project Factsheet: Catalina," March 2025.
[193] Colo. Rev. Stat. § 39-22-557.
[194] 35 Ill. Comp. Stat. 5/250.
[195] Pennsylvania Dept. of Revenue, "Regional Clean Hydrogen Hubs Tax Credit Program," June 2023.

Qualifying Hydrogen	(the top two tiers of the federal Section 45V credit)	hydrogen (the top tier of the federal Section 45V credit)	DOE's Clean Hydrogen Hubs
Credit Amount	$1 per kg of qualifying hydrogen	$1 per kg of qualifying hydrogen	$0.81 per kg of qualifying hydrogen
Who receives the tax credit?	Users of qualifying hydrogen	Users of qualifying hydrogen	Purchasers of qualifying hydrogen from regional clean hydrogen hubs—both the Mid-Atlantic Clean Hydrogen Hub and the ARCH2 Hydrogen Hub include Pennsylvania
What hydrogen end uses are eligible?	The credit is available only for hard to decarbonize industries, which includes for industrial heating (over 150 degrees Celsius) and for the use as a feedstock for industrial purposes such as steel, ammonia, and chemicals	The credit is available for all end uses *except* for light-duty vehicles, heating or cooking in residential and commercial buildings, and the combustion of hydrogen for electricity generation	The credit is available for hydrogen for use in a manufacturing facility

Tax credits for low-emissions hydrogen production and procurement should be targeted to specific end-uses, namely incumbent hydrogen uses. For example, Colorado's tax credit is only available for industrial end-users that utilize hydrogen either as a fuel for medium-temperature processes or a feedstock. The use of hydrogen for residential and commercial heating is ineligible for all three state tax credits, disincentivizing blending hydrogen into natural gas infrastructure which is already economically and environmentally inefficient. Tax credits—particularly at the state-level where it offers an additional incentive on top of federal tax credits—can direct hydrogen usage to sectors where it will have the highest climate impact.

Conclusion

Hydrogen is an essential feedstock in fertilizer production and refineries, and low-emissions hydrogen will be the key to decarbonizing these industrial sectors. While hydrogen does come with challenges—its cost, production emissions-intensity, and leakage risk, among others—it will remain necessary in these incumbent use sectors for decades to come. Thus, using limited supplies of low-emissions hydrogen in these sectors—among other prioritized end-uses—first could provide significant climate benefit by decarbonizing their existing substantial use of hydrogen.

The policy frameworks and private sector mechanisms recommended above can be relevant at numerous jurisdictions in the U.S. and can support the growth in the domestic clean energy

industry while ensuring the decarbonization transition is as efficient as possible. The successful buildout of a low-emissions hydrogen system to support decarbonization will depend on the drastic minimization of methane leaks in the upstream natural gas supply chain, the development of CCS infrastructure built with safety and environmental integrity in mind, the vast expansion of clean electricity and the U.S. transmission grid, and the adoption of best practices to minimize hydrogen leakage. With these enabling systems and the necessary policy frameworks, the U.S. can be a leader in decarbonizing incumbent uses of hydrogen in key industrial sectors.