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REPORT

HITTING THE MARK:
HOW TARGETED DEPLOYMENT OF HYDROGEN CAN MAXIMIZE CLIMATE BENEFITS

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Disclaimer: Environmental Resources Management (ERM) conducted the underlying analysis in this report. Assumptions were defined in collaboration with NRDC. The views and conclusions expressed alongside the data belong solely to NRDC.

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EXECUTIVE SUMMARY

Hydrogen has gained widespread attention in recent years due to its important role as a low-carbon resource in a decarbonized economy. Governments around the globe have released national hydrogen strategies and road maps and have enacted policies to spur low-emissions hydrogen development in their countries. Despite the initial surge in interest and project announcements, the rollout of a low-emissions hydrogen industry has been slower than expected, mostly due to high production costs compared with incumbent fossil fuel technologies, demand and policy uncertainty, and infrastructure gaps.[1] Still, there have been notable milestones in electrolyzer technology development and large-scale low-emissions hydrogen projects globally.

As low-emissions hydrogen continues to develop, it is essential to use hydrogen in applications where it can reduce greenhouse gas (GHG) emissions and to avoid low-value uses that have lower energy efficiencies, higher overall costs, and greater risks to health and safety relative to electric alternatives.

This study explores several production pathways and uses of hydrogen in a range of sectors and determines under which circumstances hydrogen provides positive climate benefits. To address this question, NRDC commissioned an analysis by Environmental Resources Management (ERM) evaluating the life-cycle GHG emissions impact of hydrogen use by various production pathways. The hydrogen production pathways included are natural gas steam methane reforming (SMR), which is the predominant production method in the United States, SMR with carbon capture and storage (CCS), and electrolysis, under different scenarios of fuel supply chain emissions and electric grid emissions intensity. The hydrogen end-use sectors included are fertilizer, steel, marine shipping fuels, light-duty vehicle road transport, power generation, and residential heating. For each of these uses, hydrogen is compared with the current baseline technology. Notably, this study also compares these uses of hydrogen against each other and against electric alternatives to show the best use cases of hydrogen from a climate perspective. The analysis uses U.S.-based data and assumptions, but findings can be generalized for other regions.

Our analysis finds that the best use of hydrogen is for industries like fertilizer, steel, and marine shipping, where it is used as a feedstock, and that using hydrogen has the most climate benefits when it is produced via electrolysis with fully clean electricity.

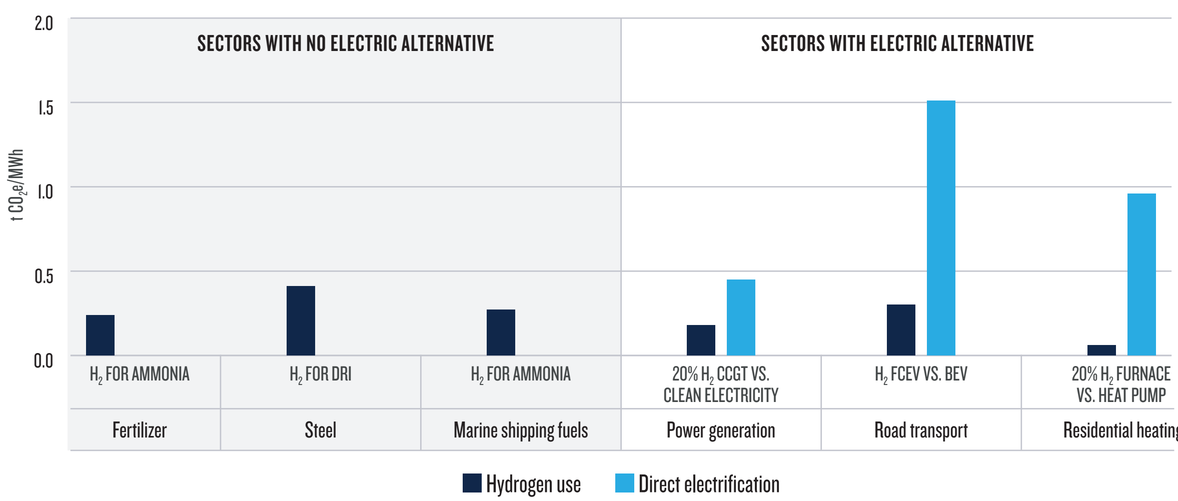
In fact, how the hydrogen is made is the most important piece of the puzzle when considering real climate benefits. Hydrogen made via electrolysis powered by fully clean electricity is zero-emissions. On the flip side, electrolysis using the current average U.S. grid mix is much more emissions-intensive than the status quo hydrogen production technology (natural gas SMR). When CCS is added to the SMR pathways, there are little to no reductions in GHG emissions, except for pathways with high carbon capture rates and low methane leakage rates. Across all pathways, standards are necessary to ensure the credibility of low-emissions hydrogen, specifically for accurate accounting of methane leakage and carbon capture rates for natural gas-based production and electricity sourcing for electrolysis.

When assessing the end uses of hydrogen, results are the same: The climate benefit depends largely on the production pathway. Across all end uses, the most GHG emissions reductions occur when hydrogen is produced via electrolysis powered by clean electricity. Assuming it is produced cleanly, hydrogen is a more promising option for industries like fertilizer, steel, and marine shipping, where it is used as a feedstock and there are no readily available direct electrification alternatives. Conversely, hydrogen is not a good option for industries where direct electrification is possible, no matter how the hydrogen is produced. These industries include light-duty vehicle road transport, residential heating, and baseload power generation, where hydrogen is one-fifth to one-half as efficient as direct electrification and can cause unnecessary air pollution from combustion (see Figure ES-1).

Especially as the recent hype around hydrogen has slowed, we can be more strategic with when and how hydrogen is deployed for the greatest climate benefit. It should be aimed at high-value end uses that likely need it as a material input for decarbonization and that actually result in GHG emissions reductions. Targeted deployment also limits other risks that come with expanded hydrogen use, such as leakage, pollution from combustion, and excessive infrastructure build-out. Maximizing hydrogen's climate benefits will require sustained policy support that includes not only production incentives and standards but also demand-side measures to develop a market for clean hydrogen.

FIGURE ES-1: EMISSIONS AVOIDED BY HYDROGEN USE VS. DIRECT ELECTRIFICATION

Emissions avoided by using 1 MWh of clean electricity, either deployed via 100 percent clean electrolytic hydrogen (dark blue bars) or direct electrification (light blue bars), compared with emissions from the baseline case in each sector. DRI means direct reduced iron; CCGT means combined cycle gas turbine; FCEV means fuel cell electric vehicle; BEV means battery electric vehicle.



INTRODUCTION

Amid momentum in climate policy over the past decade, hydrogen has been widely proposed as a clean energy resource that can reduce greenhouse gas (GHG) emissions in hard-to-abate sectors of the economy, such as steel and aviation. Private industry and federal and state governments have already begun to invest in hydrogen technologies and will start to build out the necessary infrastructure over the next decade. However, while hydrogen is an important piece of the decarbonization puzzle, it is not guaranteed to be a zero-emissions resource nor a silver bullet for tackling climate change. Its effectiveness as a climate solution depends on how it is made (i.e., its production pathway) and how it is used.

Currently, hydrogen is produced and deployed in ways that result in a large carbon footprint. About 94 percent of global hydrogen is used for refining transportation fuels and producing ammonia-based fertilizers and methanol. Essentially all of this hydrogen is produced from fossil fuel processes, using natural gas, coal, and byproducts of oil refining, without carbon capture and storage (CCS).[2] On its own, hydrogen production accounted for about 2.5 percent of global carbon dioxide (CO_2) emissions in 2023.[3] Despite hydrogen's large carbon footprint today, there are emerging pathways for cleaner production that could not only transform the existing hydrogen industry but also allow hydrogen to become a decarbonization solution across an expansive range of sectors.

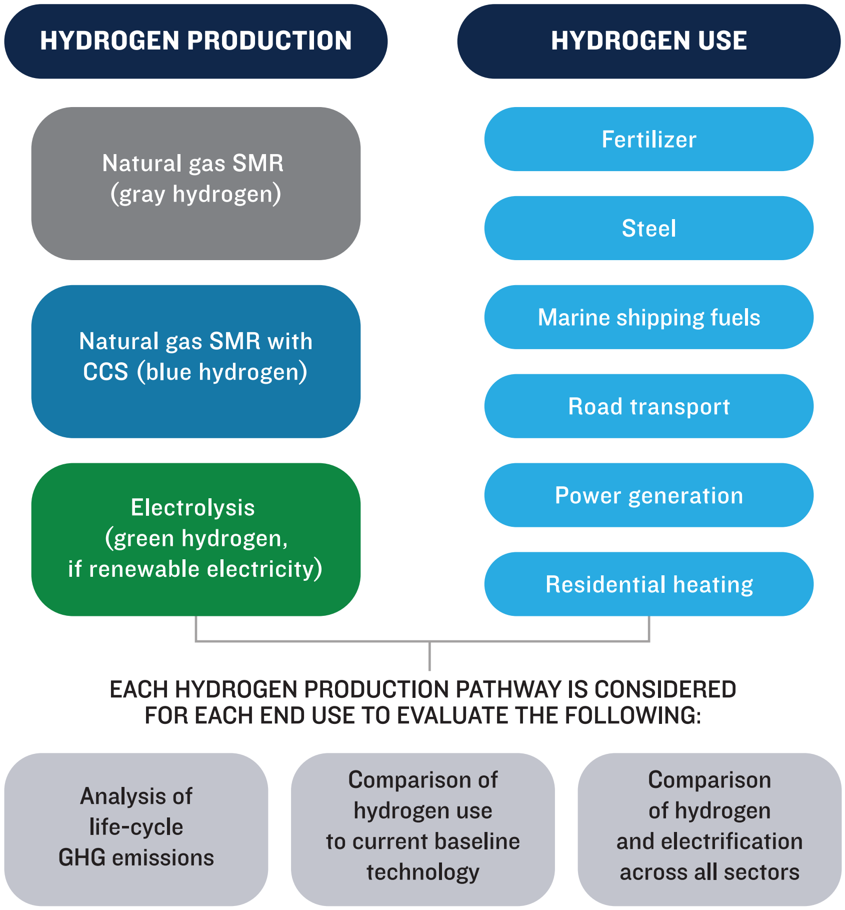
Hydrogen is attractive as a potential decarbonization solution for several reasons. Unlike conventional carbon-based fuels such as natural gas, hydrogen itself does not contain carbon, so if used as a fuel it does not directly emit carbon dioxide. Also, hydrogen is perceived as a "drop-in" replacement in some energy applications, where hydrogen fuel is substituted for the existing fuel source while keeping in place some of the established infrastructure, which could help to minimize costs associated with building new energy infrastructure.[4] For these reasons, hydrogen has been proposed as a replacement fuel for power generation, heating for buildings and industry, and transportation. This would be a big shift from today, where hydrogen is entirely used as a feedstock, or material input for making a product, rather than as a fuel for energy. It could also be used as a low-carbon feedstock in additional sectors beyond its main current uses. Likely candidates include iron and steel, marine shipping, and aviation. Before investing in these new end uses, it is important to understand the climate benefits that may—or may not—result.

Much of the recent interest in hydrogen has been driven by a supportive policy landscape. Both globally and in the United States, recent policy has signaled a growing need for clean hydrogen through national hydrogen road maps, tax incentives, procurement targets, standards, and regulations. While favorable hydrogen policy has sparked significant investment in new hydrogen projects, some of the hype has subsided since the initial surge, especially with a shortened tax credit in the United States. The level of global investment in clean hydrogen halved in 2024 relative to 2023, mostly due to sustained high costs and low demand.[5] Looking ahead, with more limited hydrogen deployment than originally projected, it is important that policy encourage the most effective hydrogen deployment, prioritizing low-emissions production technologies and end uses that actually result in reduced GHG emissions.

To understand under what circumstances hydrogen has climate benefits, and under what circumstances alternative decarbonization solutions should be deployed, NRDC commissioned a study to evaluate the GHG emissions impact of various hydrogen production pathways and a set of commonly proposed hydrogen end uses (see Figure 1). This study was conducted using a life-cycle analysis model, Argonne National Laboratory R&D Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET), to estimate life-cycle emissions of hydrogen use under varying production scenarios. The full methodology and assumptions are detailed in the appendix.

Section 1 of this report covers the hydrogen production pathways included in our analysis and the GHG emissions from each production pathway. Section 2 introduces six commonly proposed uses of hydrogen and shows the well-to-gate life-cycle emissions of hydrogen use relative to incumbent fossil fuels or other available decarbonization technologies, across different production pathways. Section 3 discusses risks associated with expanded hydrogen use. Finally, Section 4 summarizes key findings and suggests recommendations for future policy development.

FIGURE 1: SCOPE OF THIS ANALYSIS



SECTION 1: PRODUCING LOW-EMISSIONS HYDROGEN REQUIRES CLEAN ELECTRICITY

HIGHLIGHTS:

- Electrolysis using clean electricity is the only production pathway that can lead to a 100 percent GHG emissions reduction; conversely, it has the highest emissions intensity of all pathways if done with current grid electricity.
- High methane leakage rates and a carbon capture rate below 90 percent prevent natural gas-based hydrogen from qualifying as clean hydrogen ($<4\ kgCO_2e/kgH_2$), as defined by the U.S. Department of Energy (DOE) in 2023.[6] This definition set by the DOE accounts for well-to-gate life-cycle emissions in carbon dioxide equivalent (CO_2e).
- Standards are essential to ensure the sourcing of clean power for electrolysis as well as low methane leakage and high carbon capture rates for natural gas–based pathways.

Nearly all global hydrogen production today uses fossil fuel processes without CCS, which results in a large amount of GHG emissions. This section examines alternative production pathways and the extent to which GHG emissions can be reduced.

The most common production method today, which accounts for about two-thirds of global production and is the dominant method in the United States, uses natural gas in a process called steam methane reforming (SMR).[7] Without carbon capture, hydrogen produced via SMR is often referred to as gray hydrogen. Hydrogen produced via SMR with CCS is often referred to as blue hydrogen. This latter method makes up less than 1 percent of global production today but is expected to increase in the United States in the coming years.[8] Other fossil fuel production methods include coal gasification, which makes up about 20 percent of global production and occurs primarily in China, and naphtha reforming, which is a petroleum refining process that produces hydrogen as a byproduct and makes up about 15 percent of production.[9] Neither coal gasification nor byproduct hydrogen is included in this analysis due to their smaller shares of production. Other natural gas–based hydrogen production pathways, including autothermal reforming and methane pyrolysis, are also out of scope for this analysis; the same variables of methane leakage and capture rate (the latter of which is relevant to reforming) covered by our SMR analysis would apply to these natural gas–based technologies.

Electrolysis is an emerging hydrogen production process powered by electricity that converts water into hydrogen and oxygen. Electrolytic hydrogen comprises only a tiny fraction of global production but is projected to grow alongside blue hydrogen. When electrolysis is powered by renewable electricity, it is referred to as green hydrogen. In addition to a 100 percent clean electricity case, this study also analyzes cases where electricity is sourced from the current grid (see the appendix for the exact composition) and from an 80 percent clean grid.

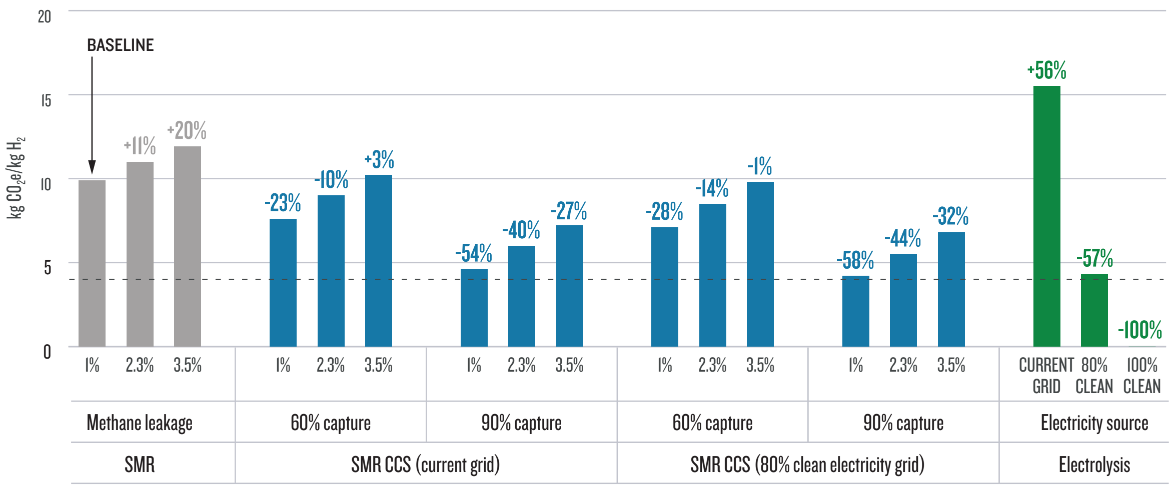
Figure 2 shows the life-cycle GHG emissions intensity of the following hydrogen production pathways: SMR, SMR with CCS, and electrolysis, for multiple scenarios. Compared with the baseline scenario (unabated SMR with a 1 percent methane leakage rate), which represents the most common production method today, two of the electrolysis scenarios are among the lowest emissions production pathways.

With electrolysis, the source of electricity can make or break its climate benefit. When powered by 100 percent clean electricity, electrolytic hydrogen achieves the most emissions reductions by far—a 100 percent reduction in GHG emissions relative to the baseline. But emissions reductions significantly diminish as the share of fossil-based electricity powering the process increases. Even with a relatively high share of clean electricity (80 percent clean), emissions relative to the baseline are reduced by only 57 percent. When powered by the average U.S. grid mix today, electrolytic hydrogen is the dirtiest process analyzed, with a 56 percent *increase* in emissions relative to the baseline. It should be noted that this analysis assumes a boundary that accounts only for the emissions from the electricity supply to power electrolyzers and is limited to three specifically defined electricity source scenarios. In reality, when electrolyzers are connected to the grid, marginal power generation supports the new load (most likely fossil fuel power, given existing resources), which means that there can be additional induced emissions in the broader power system.

These findings and the reality of adding electric loads to the grid highlight the importance of strong production standards and rigorous power sourcing requirements to ensure that electrolytic hydrogen delivers a beneficial climate outcome. See Box 1 for an explanation of the three pillars for electrolysis, which are widely adopted standards for electrolytic hydrogen to ensure that clean power is used.

FIGURE 2: GHG EMISSIONS FROM HYDROGEN PRODUCTION

Emissions from hydrogen production via natural gas steam methane reforming (SMR) (gray bars); natural gas steam methane reforming with carbon capture and storage (SMR CCS) (blue bars); and electrolysis (green bars), under different scenarios with varying methane leakage rates (1 percent, 2.3 percent, 3.5 percent), carbon capture rates, and electricity sources. The dashed line represents the US DOE definition for clean hydrogen. The baseline case is SMR production with a 1 percent methane leakage rate. Percentages above bars represent differences from the baseline case.



BOX 1: THREE PILLARS FOR ELECTROLYSIS

1. Incrementality (Additionality)

2. Hourly Matching

3. Geographic Deliverability

These three requirements for electricity sourcing are critical for verifying claims that hydrogen producers using large amounts of electricity are truly using clean energy. Electricity for electrolysis has to be 1) incremental (or additional) electricity generation, 2) used in the same hour as production occurs, and 3) used in the same geographic region where it is generated. Without meeting these standards, electrolytic hydrogen claiming to be clean could in fact be producing large amounts of emissions similar to the "current grid" scenario of Figure 2—or, even worse, similar to scenarios where electricity relies purely on natural gas or coal power.

With the three pillars, there is no need for electrolytic hydrogen projects to wait for a 100 percent clean electric grid to be beneficial to the climate, because these strong sourcing standards ensure that new clean power is paired with hydrogen production from the start. Similarly, assuming the electric grid will decarbonize over time is not justification to allow electrolytic hydrogen projects now without these standards. In fact, projects that meet these standards offer a path to advance electrolytic hydrogen production without negatively impacting the grid or system-wide emissions.

There are only a few specific scenarios where the SMR CCS pathway leads to noticeable emissions reductions (more than 50 percent). These are exclusively in cases where the capture rate of CCS is at least 90 percent and the upstream methane leakage rate is no higher than 1 percent. Among these cases, the maximum emissions savings amount to only 58 percent, relative to the baseline. With capture rates slightly higher than 90 percent, SMR CCS could qualify as clean hydrogen (<4 $kgCO_2e/kg\ H_2$), as defined by the DOE in 2023, but is unlikely to approach zero emissions.[10] Other SMR CCS scenarios with capture rates of 60 percent and higher methane leakage rates lead to minimal emissions savings, in the range of 14 percent or less, and in one scenario increases emissions slightly above the baseline case.

These results lead to a few conclusions. First, carbon capture must operate at a high capture rate to deliver any meaningful emissions reductions. Second, methane leakage has a large effect on emissions reductions. Even the high methane leakage rate examined in this study, 3.5 percent, is still far below some high-end estimates of 9 percent reported in the United States percent, which means that natural gas–based hydrogen production using supply chains with high leakage rates could be more emitting in reality.[11] Third, the source of power for operating CCS is a factor but is less impactful relative to methane leakage and capture rates. When comparing the present grid with an 80 percent clean grid, the most optimistic SMR CCS pathway only changes from a 54 percent reduction to 58 percent reduction in GHG emissions.

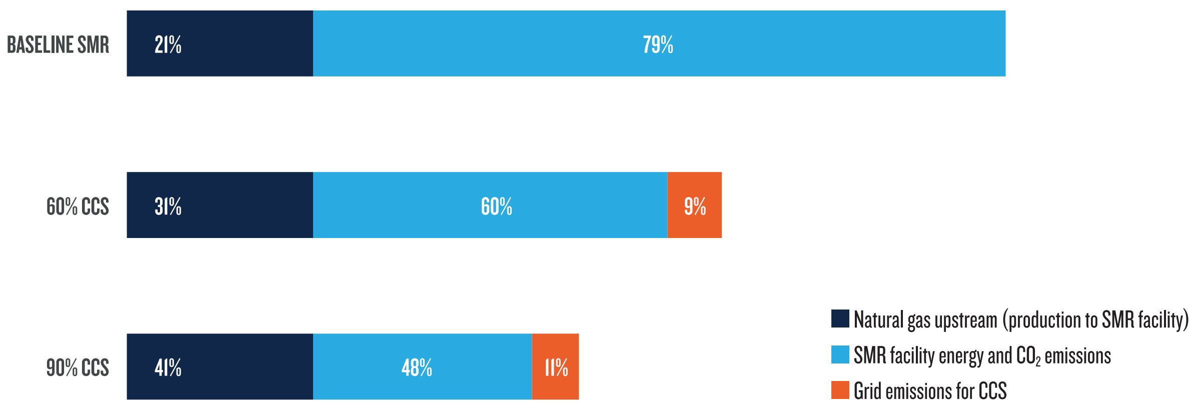
Even for the most optimistic SMR CCS pathway, there are residual emissions: upstream natural gas supply chain emissions, facility emissions from energy usage and carbon dioxide not completely captured, and electricity emissions associated with a CCS unit. Figure 3 provides a breakdown of these residual emissions for the unabated SMR and SMR CCS pathways.

About 59 percent of residual emissions from SMR with a 90 percent carbon capture rate are from energy used to run the SMR CCS facility and uncaptured CO_2. Some of these emissions could be reduced by using cleaner electricity. The rest of the emissions come from the natural gas supply chain, which includes methane leakage, even with the optimistic 1 percent leakage rate. Some upstream natural gas emissions can be reduced through improved leakage detection, minimized gas flaring, and electrification and carbon capture at processing plants.[12]

Overall, the findings from Figure 3 highlight the importance of strong production standards for natural gas–based hydrogen, standards that require 1) accurate methane leakage and upstream natural gas emissions accounting and an ambitious threshold to limit leakage (e.g., at 1 percent or less); and 2) high shares of carbon capture, at no less than 90 percent.

FIGURE 3: EMISSIONS BREAKDOWN OF NATURAL GAS–BASED HYDROGEN

Emissions breakdown of hydrogen production from natural gas steam methane reformation without carbon capture and storage (baseline SMR) and with carbon capture and storage (SMR with CCS at a 60 percent capture rate and 90 percent capture rate). See the appendix for additional details on assumptions.[13]



SECTION 2: HYDROGEN IS PROMISING FOR SOME—BUT NOT ALL—USES OUTSIDE OF CURRENT SECTORS

The enthusiasm around hydrogen involves expanding its use far beyond current sectors. This section assesses commonly proposed uses of hydrogen in six sectors: fertilizer, steel, marine shipping fuels, road transport, power generation, and residential heating.

Almost all of global hydrogen demand (97 million metric tons in 2023) is currently used in the refining and industrial sectors as a feedstock to produce fuels and chemicals.[14] The exact breakdown is 44 percent in refining, 33 percent in ammonia production for fertilizers, 16 percent in methanol production for chemicals, 5 percent in natural gas–based direct reduced iron steel production, and the rest in niche industrial applications.[15] Hydrogen is considered a versatile resource that could be used as a low-carbon feedstock in a broader range of industries and potentially as a fuel in sectors where it is not used today.

Use of hydrogen has been proposed for each major sector of the economy—industry, power generation, transportation, and buildings—and while it could be technically feasible to adapt all of these systems to incorporate hydrogen, real-world barriers stand in the way, namely the costs of production and transport; lack of infrastructure; concerns over safety, health, and overall energy efficiency; and emissions impacts. Several recent studies have assessed proposed hydrogen end uses by considering these barriers and ranking uses accordingly, from necessary to uncompetitive.[16]

In considering these alternative uses, this analysis is specifically focused on GHG emissions impacts but considers overall energy efficiency and other factors in discussion sections. Ultimately, the value that hydrogen offers in terms of climate benefits varies greatly, depending on how it is produced and how it is used relative to existing options.

2.1 FERTILIZER

HIGHLIGHTS:

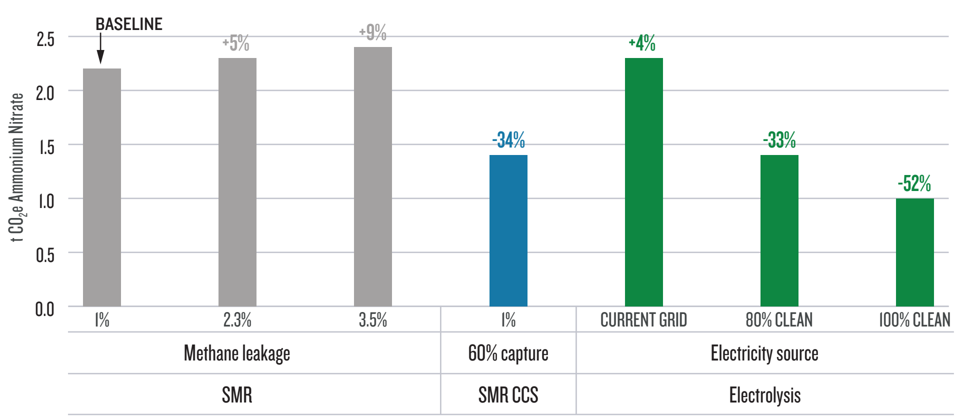
- Hydrogen is used to produce ammonia, which can be used as a fertilizer itself or as a key component of nitrogen-based fertilizer. In the United States today, ammonia is predominantly produced using SMR hydrogen. Fertilizer emissions can be reduced if ammonia production uses SMR CCS or electrolytic hydrogen.
- Fertilizer using electrolytic hydrogen with a 100 percent clean grid has the lowest emissions impact.
- Other parts of fertilizer production, such as nitric acid production, contribute to overall GHG emissions.

Fertilizer is the only use case examined in this analysis that already relies on hydrogen. The type of fertilizer evaluated here is ammonium nitrate, a type of nitrogen-based fertilizer that constitutes 59 percent of US fertilizer use and is made by reacting ammonia and nitric acid.[17] Producing that ammonia requires energy-intensive hydrogen production. Almost all ammonia production in the United States uses natural gas–based SMR hydrogen production. Therefore, the baseline case in this analysis for fertilizer production uses SMR hydrogen.

This analysis evaluates the full emissions of ammonium nitrate, which includes emissions from producing ammonia as well as from the production of nitric acid. Since parts of the fertilizer production process do not involve hydrogen, some emissions will remain unimpacted by different hydrogen pathways, such as emissions of nitrous oxide (N_2O), an extremely potent GHG, during the production of nitric acid. Figure 4 shows the life-cycle GHG emissions intensity of ammonium nitrate fertilizer for multiple scenarios of hydrogen production.

FIGURE 4: GHG EMISSIONS FROM FERTILIZER (AMMONIUM NITRATE) PRODUCTION

Emissions from fertilizer (ammonium nitrate) production via natural gas steam methane reforming (SMR), natural gas steam methane reforming with carbon capture and storage (SMR CCS), and electrolysis, under different scenarios with varying methane leakage rates (1 percent, 2.3 percent, 3.5 percent) and electricity sources. Note that the SMR CCS scenarios for ammonia are limited in GREET; see the appendix. The baseline case is SMR fertilizer production with a 1 percent methane leakage rate. Percentages above bars represent differences from the baseline case.



Compared with the baseline case, adding CCS at a 60 percent capture rate to hydrogen production reduces total fertilizer emissions by 34 percent. Using electrolytic hydrogen with a 100 percent clean grid, which zeroes out emissions from hydrogen production, reduces total fertilizer emissions by 52 percent. The remaining emissions are attributed to N_2O emissions from nitric acid production and electricity consumption in other processing steps, such as nitrogen production.

Using current grid mix electricity for electrolysis results in slightly higher overall fertilizer emissions than from the baseline case. Therefore, in order for electrolytic hydrogen to be a decarbonization solution for ammonia and fertilizer production, electricity sourcing standards are critical.

2.2 STEEL

HIGHLIGHTS:

- Most primary steel production relies on coal and releases large amounts of carbon dioxide due to combustion and process chemistry. A different process, called direct reduction of iron (DRI), could use 100 percent hydrogen to eliminate these onsite emissions.
- Life cycle steel production emissions can be reduced by 90 percent through DRI with electrolytic hydrogen powered by 100 percent clean power.
- Steel produced from emissions-intensive hydrogen, such as electrolytic hydrogen powered by the current grid or SMR hydrogen with high methane leakage and a low capture rate, leads to minimal emissions reductions or even a slight increase from the baseline.
- For all DRI-based steel that uses an electric arc furnace (EAF), the emissions intensity of the electricity has a large effect on overall steel emissions.

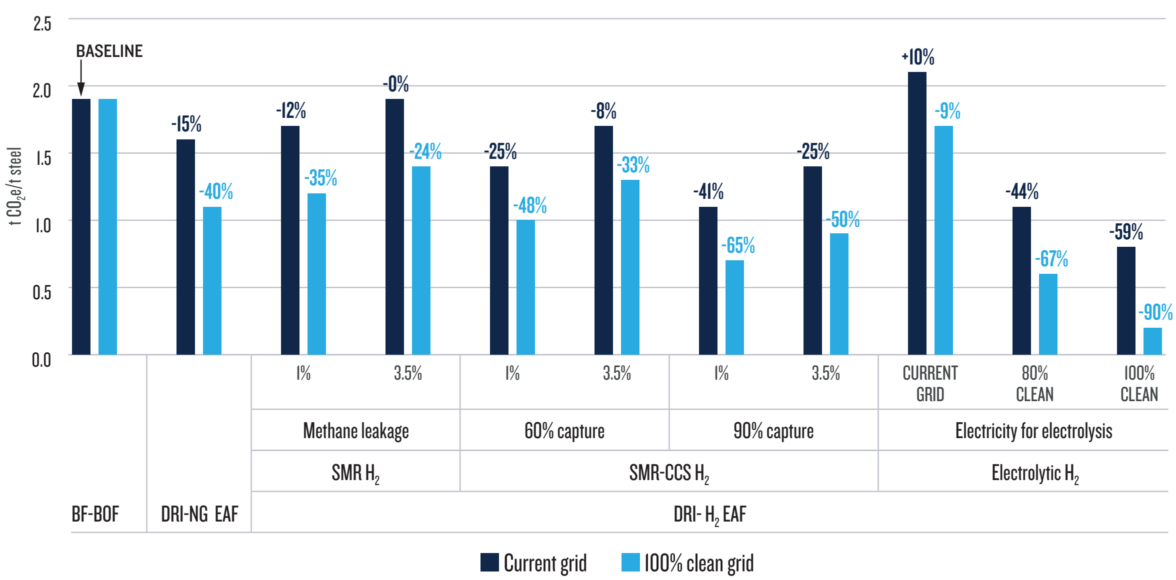
The bulk of today's primary steel is produced via a coal-fired blast furnace and basic oxygen furnace (BF-BOF).[18] This is a heavily emitting process, with the majority of emissions occurring at the blast furnace stage. Blast furnace emissions come from the combustion of carbon-based fuels to produce heat at extremely high temperatures, as well as from the chemistry of the reaction when converting iron ore to iron, which itself releases carbon dioxide.[19]

Alternatively, the direct reduction of iron (DRI) process is rapidly advancing as a potential cleaner substitute for coal-fired blast furnaces, as it would replace the most emissions-intensive step in traditional steelmaking.[20] The DRI process is commercialized today and uses natural gas. In the process, natural gas is reformed into syngas, a mix of hydrogen and carbon monoxide that drives the ironmaking step of steel production. Another promising option is to use 100 percent hydrogen directly, which could eliminate upstream emissions. Regardless of how DRI is produced, the iron must then be further processed by an electric arc furnace (EAF) to produce steel.[21] EAFs are a mature, commercialized technology that already makes up an entire secondary (scrap-based) steel market.[22]

This analysis compares the traditional BF-BOF route with DRI-EAF. Figure 5 shows the life-cycle emissions intensity of steel produced via BF-BOF with coal, DRI-EAF with natural gas, and DRI-EAF with 100 percent hydrogen, under multiple hydrogen production pathways.

FIGURE 5: GHG EMISSIONS FROM STEEL PRODUCTION

Emissions from steel production via blast furnace–basic oxygen furnace (BF-BOF), natural gas direct reduced iron with electric arc furnace (DRI-NG EAF), and 100 percent hydrogen DRI with EAF (DRI-H_2 EAF), under multiple hydrogen production pathways. Dark blue bars represent current grid electricity (for all other electricity including EAF); light blue bars represent 100 percent clean electricity. The baseline case is BF-BOF steel. Percentages above bars represent differences from the baseline case.



Due to the high electricity demand from the DRI-EAF process, particularly the EAF, the source of the electricity for DRI-EAF is a significant factor in determining emissions reductions relative to the baseline case. For example, even when using 100 percent clean electrolytic hydrogen, the steelmaking process can achieve a maximum emissions reduction of only 59 percent relative to status quo steel if the EAF portion is still powered with today's average grid mix. Powering the EAF with clean electricity instead substantially improves the climate benefit of all types of DRI steel. The maximum emissions reduction for DRI steel using a 100 percent clean grid for both electrolysis and the EAF process is 90 percent, with remaining emissions coming from upstream mining and processing. In contrast, when using current grid electricity for both hydrogen production and the DRI-EAF process, emissions are 10 percent *higher* than the baseline BF-BOF route.

The emissions intensity of hydrogen is also critical in ensuring that hydrogen-DRI steel delivers on its promise. Outside of electrolytic hydrogen, the best scenario among the SMR CCS hydrogen pathways for DRI steel, with a 1 percent methane leakage rate and 90 percent carbon capture rate, shows a 65 percent reduction in emissions from the baseline when using clean electricity.

Last, natural gas–based DRI is the most common of the DRI pathways today but reaches emissions reductions of only 40 percent at best, whereas H_2-DRI steel can reach reductions of 90 percent. DRI plants should be designed to operate on 100 percent hydrogen, even if they also use natural gas or a natural gas–hydrogen blend for some transitional period.

Overall, these results highlight the importance of 1) setting strong standards for hydrogen production as discussed in previous sections, 2) accelerating the decarbonization of the electricity grid and/or advancing electricity sourcing strategies for steel manufacturers to contract for clean electricity, and 3) setting requirements such that new DRI steel plants must be designed to be hydrogen ready.

2.3 MARINE SHIPPING FUELS

HIGHLIGHTS:

- Ammonia is a potential alternative to replace conventional shipping fuels, such as heavy fuel oil (HFO).
- Ammonia produced using electrolytic hydrogen with 100 percent clean electricity can eliminate up to 98 percent of shipping fuel GHG emissions.
- Ammonia produced from SMR hydrogen (gray hydrogen) offers no significant benefits compared with HFO and actually increases emissions slightly with high methane leakage. SMR CCS hydrogen with moderate carbon capture can reduce emissions by 66 percent.

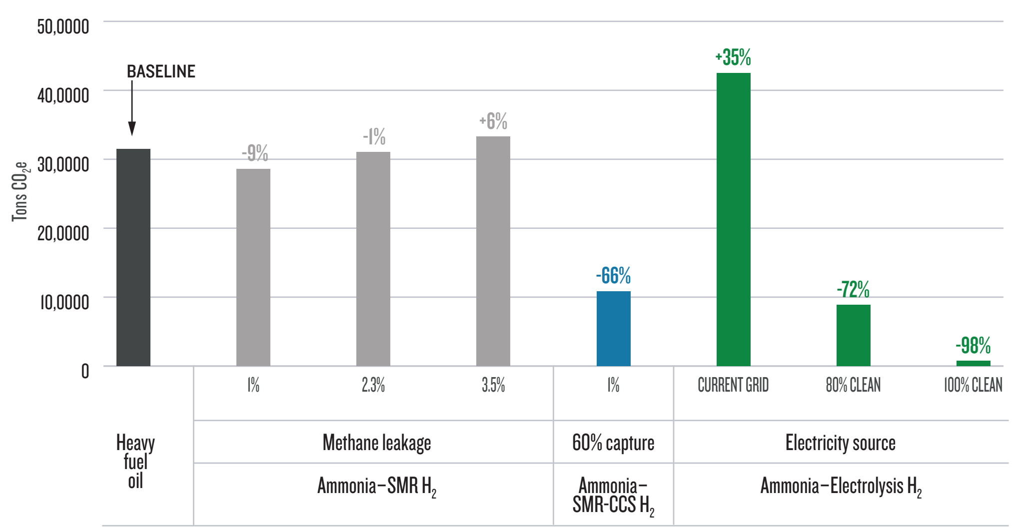
Long-distance shipping typically uses heavy fuel oil (HFO), a particularly high-emitting fuel. Emissions from maritime shipping vessels account for 3 percent of global emissions, and currently there is no consensus on the best decarbonized energy source to replace HFO.[23] For long distances, especially between continents, it is widely considered impractical to use batteries, which would need much higher energy densities than they are capable of providing.

The main options considered for cleaner long-distance shipping fuels are ammonia, methanol, and biofuels. Methanol is gaining momentum as a shipping fuel, possibly more so than ammonia.[24] However, unlike ammonia, for which the main feedstocks are hydrogen and nitrogen (which is abundant in air), methanol requires a source of carbon as well as hydrogen. For methanol to be produced in a low-emissions way, the source of carbon must be net-zero, such as from sustainable biomass or from carbon dioxide acquired from direct air capture technologies. Due to this emissions accounting complexity, this analysis excludes methanol and biofuels and only considers various hydrogen production pathways for ammonia, relative to HFO. However, the conclusions drawn from ammonia can also apply to the hydrogen supply for producing methanol or refining biofuels.

Figure 6 shows the life-cycle emissions intensity in GHG emissions per gallon of shipping fuel, comparing HFO and ammonia produced from various hydrogen pathways. While

FIGURE 6: GHG EMISSIONS FROM MARINE SHIPPING FUELS

Emissions from marine shipping fuel production and combustion over 145 vessel trips, comparing heavy fuel oil to ammonia produced from multiple hydrogen production pathways. Note that the SMR CCS scenarios for ammonia are limited in GREET; see the appendix. The baseline case is heavy fuel oil. Percentages above bars represent the difference from the baseline case.



this analysis considers the climate impacts of switching from heavy fuel oil to ammonia, it does not consider other impacts to the environment, such as toxicity from potential leakage of ammonia or potential impacts to worker safety.

Ammonia produced from unabated SMR hydrogen results in minimal changes in emissions compared with the baseline case and even increases emissions slightly with high methane leakage. Blue ammonia, or ammonia produced from SMR CCS hydrogen at a moderate capture rate, results in a noticeable emissions reduction of 66 percent. Even higher emissions reductions can be achieved with ammonia produced from electrolytic hydrogen that is powered by clean electricity, reaching a maximum reduction of 98 percent relative to the baseline. The remaining 2 percent of GHG emissions in this case comes from N_2O released during combustion. With incomplete combustion of ammonia, there is a risk of increased N_2O emissions and, thus, smaller GHG emissions reductions. Potential adverse side effects with ammonia combustion need to be better understood and mitigated if it is to be a solution for marine shipping.[25]

2.4 ROAD TRANSPORT

HIGHLIGHTS:

- Hydrogen has been proposed for light-duty vehicles and medium- and heavy-duty trucks. This analysis covers only hydrogen use in light-duty vehicles alongside alternatives.
- Hydrogen fuel cell electric vehicles (FCEVs) reduce emissions in all scenarios due to the greater efficiency of electric motors relative to internal combustion engines (ICEs).
- However, battery electric vehicles (BEVs) result in greater emissions reductions than FCEVs; even when powered by the present grid, BEVs outperform even the most optimistic SMR hydrogen with CCS in an FCEV.
- FCEVs using electrolytic hydrogen are one-fifth as energy efficient as BEVs.

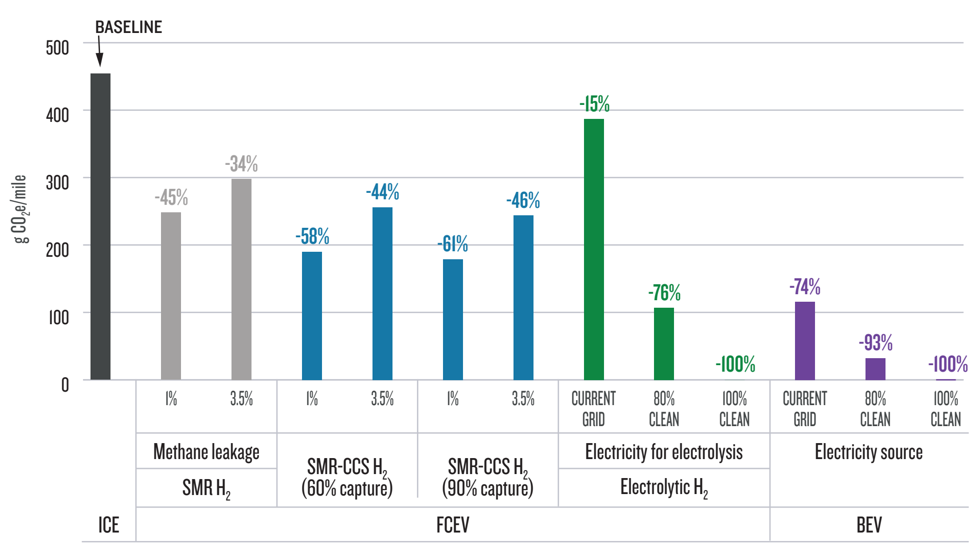
In the United States, about 24 percent of total GHG emissions come from light-duty vehicles and medium- and heavy-duty trucks, creating a competition for cleaner alternatives.[26] Among light-duty vehicles, battery electric vehicles (BEVs) have clearly surpassed hydrogen fuel cell electric vehicles (FCEVs). BEVs have accelerated in popularity in recent years, making up about 9 percent of U.S. light-duty car sales as of September 2024.[27] However, a tiny market for FCEVs remains, especially in California. For ease of comparison, this analysis selectively evaluates hydrogen use in light-duty vehicles only; the conclusions are likely relevant to medium- and heavy-duty trucks as well, where neither hydrogen nor electric alternatives have yet made a dent in the market.[28] For heavy-duty trucks, hydrogen remains relevant due to its higher energy density compared with batteries and its faster refueling time.

Figure 7 shows the life-cycle emissions intensity of light-duty vehicles in GHG emissions per mile traveled, for internal combustion engine (ICE) vehicles, BEVs, and FCEVs under multiple hydrogen production pathways.

In contrast to other uses of hydrogen as a fuel (e.g., combustion in power plants and buildings), this analysis shows that hydrogen FCEVs reduce emissions relative to the internal combustion car in all the production pathways chosen—even unabated SMR hydrogen with a high leak rate. This is because of the higher efficiency of an electric motor compared with an ICE vehicle: Typically, an electric motor delivers around 77 percent of the electric energy to the wheels, whereas an ICE vehicle delivers only 12 to 30 percent of the energy in gasoline to the wheels.[29] The inefficiency of ICEs is due to most of the fuel's energy being lost as heat and additional mechanical systems.

FIGURE 7: GHG EMISSIONS FROM LIGHT-DUTY VEHICLE TRANSPORT

Emissions from light-duty vehicle road transport, comparing an internal combustion engine (ICE) vehicle, a hydrogen fuel cell electric vehicle (FCEV) produced from multiple hydrogen production pathways, and a battery electric vehicle (BEV). The baseline case is an ICE vehicle. Percentages above bars represent differences from the baseline case.



Unabated SMR hydrogen reduces emissions by 34 to 45 percent compared with an ICE vehicle, depending on the methane leakage rate. If methane leakage is kept low, then FCEVs with SMR CCS hydrogen reduce emissions by 58 to 61 percent, depending on the capture rate. If methane leakage is high, then the emissions reductions are lower, only 44 to 46 percent.

Even electrolytic hydrogen produced using current grid electricity, the most emissions-intensive production pathway included, reduces emissions in an FCEV relative to an ICE due to engine inefficiency. The reduction is a modest 15 percent using current grid electrolytic hydrogen, whereas 100 percent clean electrolytic hydrogen zeroes out all emissions.

However, despite the 100 percent clean electrolytic hydrogen FCEV having the potential to zero out GHG emissions, a BEV can achieve this while also using one-fifth as much electricity as an FCEV to travel the same distance. (See Section 2.7 for a deep dive on the relative efficiency of using clean electricity for electrolytic hydrogen compared with direct electrification.)

2.5 POWER GENERATION

HIGHLIGHTS:

- Combusting hydrogen for power delivers little climate benefit, even in cases where the hydrogen produced has very low carbon emissions.
- Unless the hydrogen produced is very low carbon, blending hydrogen in natural gas power plants increases emissions relative to combusting only natural gas.
- For the power sector broadly, zero-emissions power generation sources like wind and solar paired with energy storage are more efficient options than combusting or blending hydrogen. However, hydrogen could be of value to the power grid in certain cases as a long-duration energy storage resource or as a dispatchable, peaking resource during grid emergencies.

Some hydrogen enthusiasts have suggested combusting hydrogen as a way to generate power. However, replacing any amount of natural gas in the power sector with hydrogen produced from unabated SMR increases emissions in all scenarios. The higher the blend of hydrogen, the more emissions increase. Energy conversions are never 100 percent efficient; combusting natural gas directly is more efficient than converting it to hydrogen via SMR and then combusting the hydrogen. Therefore, without CCS, combusting SMR hydrogen will always increase emissions relative to combusting natural gas.

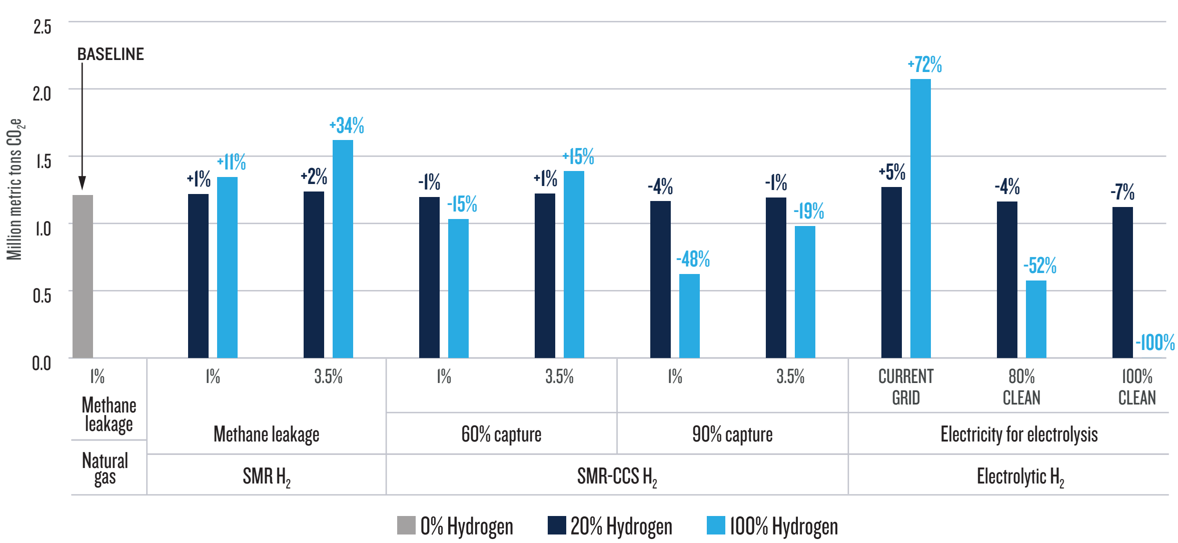
Combusting hydrogen produces about one-third the energy of the same volume of natural gas.[30] This means that three times the volume of hydrogen must be combusted to deliver the same amount of electricity. Consequently, low hydrogen-natural gas blend rates by volume, like 20 percent hydrogen, deliver very little benefit even if the hydrogen is produced with low emissions. The combined impact of those dynamics leads to negative climate outcomes and emissions increases relative to a baseline of only natural gas combustion, particularly when the hydrogen is produced in a carbon-intensive way.

Figure 8 shows the annual GHG emissions from a combined cycle gas turbine (CCGT) power plant, with different levels of hydrogen blending and under multiple hydrogen production pathways.

In SMR scenarios with high methane leakage and no or low carbon capture rates, total emissions increase. One SMR CCS scenario with low methane leakage and a high capture rate results in an emissions reduction relative to natural gas power, but the reduction is only 48 percent. The substantial amount of energy that would be required in this scenario, due to the series of energy conversions and powering the carbon capture equipment, on top of the need to burn three times the volume of hydrogen relative to fossil gas, are not worth

FIGURE 8: ANNUAL GHG EMISSIONS FROM A COMBINED CYCLE GAS TURBINE POWER PLANT

Annual emissions of a 1000 MW gas combustion combined cycle gas turbine (CCGT) power plant, comparing natural gas (0 percent hydrogen), 20 percent hydrogen/80 percent natural gas (20 percent hydrogen blend), and 100 percent hydrogen, for a range of hydrogen production pathways. The baseline case is a 100 percent natural gas power plant with a 1 percent methane leakage rate. Percentages above bars represent differences from the baseline case.



the insufficient emissions reductions that can be achieved by blending SMR hydrogen with natural gas.

Electrolytic hydrogen in the power sector presents risks similar to those presented by SMR hydrogen. That is, burning electrolytic hydrogen in place of natural gas increases emissions if it is produced with low standards, such as using the current grid mix. The emissions resulting from combusting electrolytic hydrogen decrease as the source of electricity becomes cleaner, as described in earlier sections. However, the share of clean electricity powering hydrogen production must be close to 100 percent to deliver meaningful climate benefits; even when powered by 80 percent clean electricity, the 100 percent hydrogen case reduces emissions by only 52 percent relative to burning natural gas, due to the energy intensity of electrolysis.

From a climate perspective, it appears that the 100 percent clean electrolytic hydrogen case, resulting in 100 percent emissions reductions from the baseline, is equivalent to direct renewable generation. However, this doesn't account for the inefficiency of producing hydrogen and converting it back to electricity. To generate the same amount of electricity would require 2.8 times more clean electricity if combusting electrolytic hydrogen. (See Section 2.7 for a deep dive on the relative efficiency of using clean electricity for electrolytic hydrogen compared with direct electrification.)

The inefficiency of using hydrogen for around-the-clock bulk power generation is apparent, but there could be potential value in using hydrogen as a form of long-duration energy storage in the power sector.[31] In this way, hydrogen produced via excess renewable electricity could provide a dispatchable resource to support grid reliability, especially during periods of grid stress or extreme weather.

2.6 RESIDENTIAL HEATING

HIGHLIGHTS:

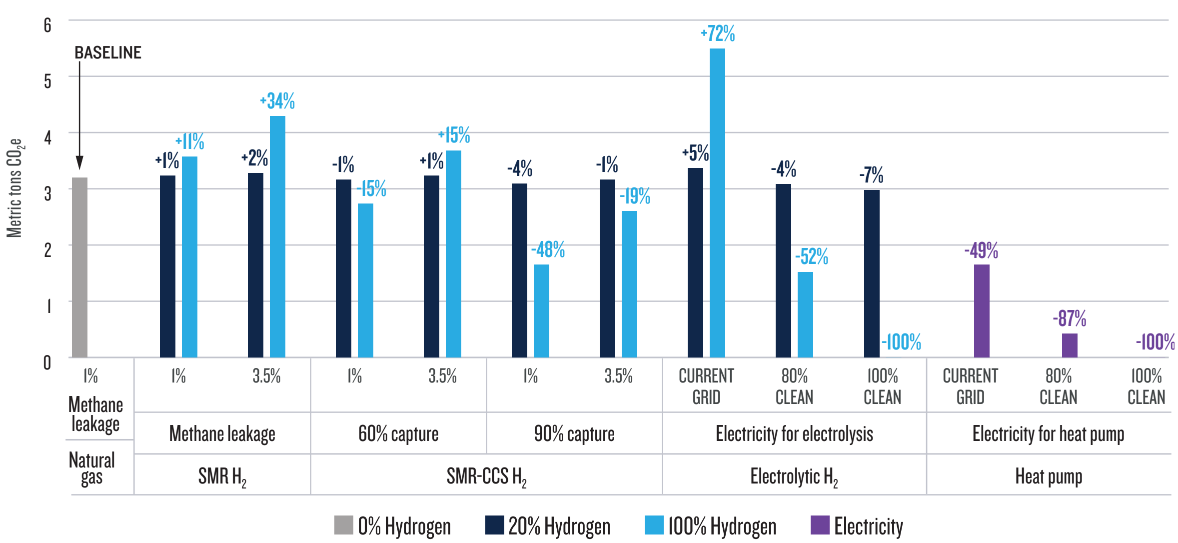
- Blending hydrogen for residential heating has the same drawbacks as blending hydrogen for power generation: inefficiency and minimal emissions reductions in most scenarios.
- Blending electrolytic hydrogen powered by the current grid in a furnace leads to emissions increases relative to a baseline natural gas furnace.
- An air source heat pump reduces emissions relative to a baseline natural gas furnace even when powered by the current grid.

Substituting hydrogen for natural gas in a residential furnace has results similar to those in the power sector because in both cases hydrogen combustion is displacing natural gas combustion. In this analysis, we assume no change to the efficiency of the furnace when switching among burning natural gas, hydrogen, and blends of the two. It should be noted that safely running an existing gas furnace with a blend of hydrogen and natural gas is limited to 20 percent hydrogen; while we include an analysis of a 100 percent hydrogen substitution, to do so would require new equipment, making it a costly pathway. Our analysis focuses on comparing the emissions from the baseline case (a natural gas furnace) to hydrogen blending in a natural gas furnace, a fully hydrogen furnace, and an air source heat pump. Generally, heat pumps are poised to be the predominant decarbonization option for the bulk of buildings.

Figure 9 shows the annual life-cycle emissions from heating an average-size single-family home, comparing a natural gas furnace to various blends of hydrogen under multiple hydrogen production pathways and to an electric heat pump.

FIGURE 9: ANNUAL GHG EMISSIONS FROM HEATING A SINGLE-FAMILY HOME

Annual emissions from heating an average single-family home. The same heat load is delivered either by a furnace fueled by natural gas (0 percent hydrogen), 20 percent hydrogen/80 percent natural gas (20 percent hydrogen blend), and 100 percent hydrogen, under multiple hydrogen production pathways, or by a heat pump. The baseline case is a 100 percent natural gas furnace with a 1 percent methane leakage rate. Percentages above bars represent differences from the baseline case.



The results reveal stark differences between combusting hydrogen for heat and using a heat pump—in almost all scenarios, the heat pump results in fewer emissions. Blending electrolytic hydrogen powered by the current fossil-heavy grid results in higher emissions relative to a baseline natural gas furnace. In contrast, a heat pump powered by the current grid results in a 49 percent reduction in emissions relative to the baseline. In addition, those emissions reductions assume no improvements in insulation that would typically be paired with the installation of a heat pump, which could lead to a larger reduction in emissions. This is due to the impressive energy efficiency of an air source heat pump (up to 300 percent) compared with a gas furnace (90 to 95 percent).[32] Rather than directly converting electricity or fuel to heat like a furnace or resistance heater, the heat pump uses electricity to move heat from the outside to the inside, like a reverse refrigerator or air conditioner.

These findings confirm that policies supporting the deployment of heat pumps need not impose rigorous requirements on the source of electricity powering the process. This is not the case for hydrogen, for which such requirements are necessary to avoid an emissions outcome worse than status quo.

Additionally, while the 100 percent clean electricity scenarios for electrolytic hydrogen and the heat pump are the same on a purely emissions basis, the superior energy efficiency of the heat pump means that heat pumps could save a larger amount of emissions relative to electrolytic hydrogen in home furnaces using the same amount of clean electricity. (See Section 2.7 for a deep dive on the relative efficiency of using clean electricity for electrolytic hydrogen compared with direct electrification.) Moreover, a hydrogen furnace would also require significant gas pipeline upgrades that add costs and raise safety concerns.

2.7 SUMMARY: COMPARING THE USES OF HYDROGEN

HIGHLIGHTS:

- The best use cases for hydrogen studied in this analysis, based on the quantity of emissions avoided, are fertilizer production, steel production, and marine shipping fuel production.
- Hydrogen can reduce emissions in light-duty vehicles compared with conventional ICEs, but much less so than using the same energy via direct electrification.
- Buildings and power generation offer the lowest emissions reductions per unit of hydrogen, and both have much more efficient direct electrification options, making these sectors bad use cases for hydrogen.

The previous sections show that hydrogen use in fertilizer, steel, and marine shipping can lead to GHG emissions savings, particularly when produced electrolytically with clean electricity. However, hydrogen use in road transport, power generation, and residential heating is less valuable, as there are alternatives that can achieve more emissions savings in these sectors. Here, this section compares all the end uses on an equal basis by normalizing emissions savings across sectors and includes a comparison with direct electrification where applicable.

Decarbonizing the economy rapidly and affordably is the ultimate objective driving this analysis, and hydrogen must be deployed strategically to meet that goal. While electrolytic hydrogen powered by clean electricity could support this objective, its non-targeted deployment risks hindering it. Electrolytic hydrogen requires large volumes of electricity; if hydrogen deployment becomes too widespread, electrolytic hydrogen production could dangerously extend the timeline for decarbonization, adding climate impacts and increasing costs for consumers. Targeted hydrogen deployment in the most efficient and high-value use cases is therefore fundamentally important. Fortunately, there are more efficient, cost-effective alternatives in a range of hydrogen use cases (e.g., heat pumps for residential heating, battery electric vehicles for road transport).

A useful metric to assess the relative value of using hydrogen in different end uses is to compare the amount of emissions that can be avoided for a given unit of clean energy. Given the generation of 1 megawatt-hour (MWh) of clean electricity, we compare the amount of emissions that can be displaced if this 1 MWh is used directly, such as in a BEV in place of an ICE, versus indirectly to produce electrolytic hydrogen for use in an FCEV in place of an ICE.

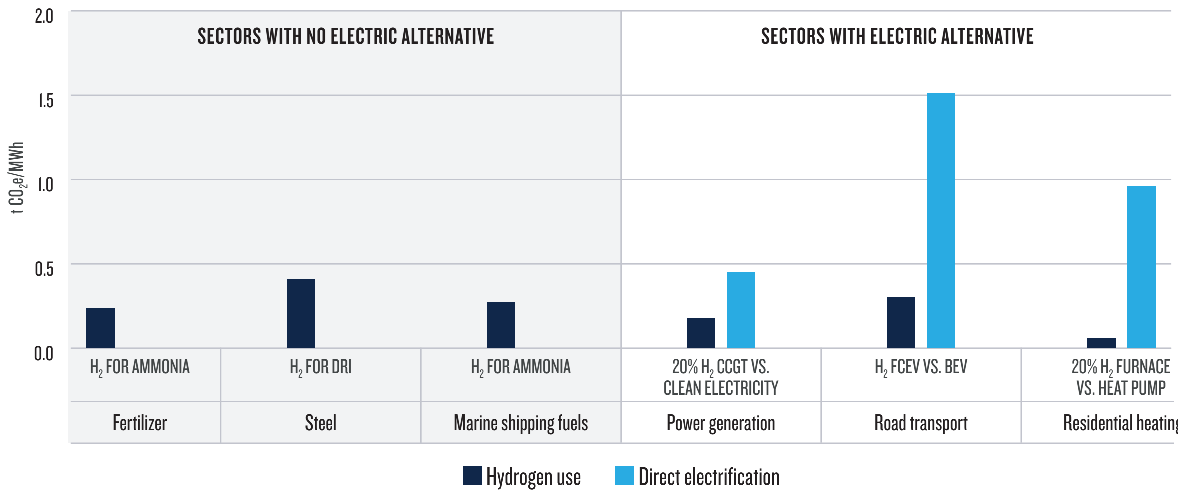
Figure 10 shows the relative payoff of using clean electricity to deploy hydrogen in different sectors and compares it to direct electrification where possible. In the example of FCEV versus BEV, using 1 MWh of clean energy in a BEV displaces five times the amount of GHG emissions compared with using 1 MWh in an FCEV (1.51 vs. 0.30 tCO_2e). This means that a BEV also requires one-fifth the electricity relative to an FCEV, given the same annual driving demand for a light-duty vehicle in both cases.

In a use such as H_2-DRI-EAF for steelmaking, using 1 MWh of clean electricity to create hydrogen displaces roughly 0.41 tCO_2e. Given that there is no commercially available direct electrification alternative for primary steelmaking, this makes steel a much more compelling use for hydrogen than a light-duty FCEV, for example. Fertilizer and marine shipping fuels have a level of emissions savings similar to that of steel (0.37 and 0.29 tCO_2e/MWh, respectively) and also have no viable direct electrification alternatives. There are some emerging electric technologies for steel and short-distance marine shipping that may change the calculation in the future, but they are not yet commercially available.[33]

The sectors with viable electric alternatives present a less favorable case for hydrogen. In power generation, emissions savings from using 1 MWh of clean electricity to displace natural gas power generation is 0.45 tCO_2e/MWh, whereas using 1 MWh to produce hydrogen and blend it with natural gas in a gas power plant saves only 0.18 tCO_2e/MWh. For road transport and residential heating, both electric alternatives (BEVs and heat pumps, respectively) significantly outperform hydrogen use in terms of emissions avoided.

FIGURE 10: EMISSIONS AVOIDED BY HYDROGEN USE VS. DIRECT ELECTRIFICATION

Emissions avoided by using 1 MWh of clean electricity, either deployed via 100 percent clean electrolytic hydrogen (dark blue bars) or direct electrification (light blue bars), compared with emissions from the baseline case in each sector.



SECTION 3: OTHER RISKS TO MANAGE WITH HYDROGEN USE

Besides the risk of inadvertently adding more GHG emissions with high-emission hydrogen production routes and ineffective uses, there are several non-climate risks to manage with an expanded hydrogen sector. These risks include emissions of nitrogen oxides (NOx) from hydrogen combustion, hydrogen leakage, and environmental impacts from infrastructure build-out.

NOx EMISSIONS

In applications where hydrogen or hydrogen derivatives could be used as a fuel, such as power generation, residential heating, and marine shipping, combustion of hydrogen or ammonia can lead to the formation of NOx. NOx is a group of compounds composed of nitrogen and oxygen, with the most common being nitric oxide (NO) and nitrogen dioxide (NO_2).[34] NOx emissions can negatively affect human health (e.g., olfactory issues, respiratory symptoms and infections) and environmental health (e.g., acid rain, hazy air, eutrophication).[35] Currently, the U.S. Environmental Protection Agency (EPA) regulates NO_2 as a criteria air pollutant and advises taking mitigation measures where it is present.[36]

The two main approaches to minimizing NOx emissions are 1) controlling combustion conditions, and 2) after-treatment and removal. Minimizing NOx via control of combustion conditions is possible, but it can lead to lower power output and performance. The challenge with high NOx emissions during combustion arises mostly from high flame temperatures and repurposing existing combustors for hydrogen use; new combustion equipment and lower combustion temperatures can limit NOx formation.[37] After-treatment and removal of NOx such as through selective catalytic reduction and selective noncatalytic reduction are possible and used often, but this approach increases cost and complexity in equipment systems.[38] These mitigation approaches apply primarily to large-scale combustion, for power generation for example, but they are not feasible for individual residential appliances. There is therefore a need to bolster understanding of the scope of NOx emissions and the effectiveness of solutions before deploying hydrogen combustion projects.

HYDROGEN LEAKAGE

Expanding hydrogen use can also lead to hydrogen leakage throughout its supply chain, and this contributes to safety concerns and potential increases in atmospheric warming. Hydrogen is the smallest molecule and much smaller than methane (the main component of natural gas), which can make it prone to leakage, particularly when being used in infrastructure like pipelines or combustion turbines that were designed for natural gas. While it is highly flammable in air, it also has a high diffusion rate, diluting quickly into nonflammable concentrations. Still, systems using hydrogen in confined areas need to manage its leakage potential. If leaked in large amounts into the atmosphere, hydrogen can indirectly cause warming through its reactions with other molecules in the atmosphere and has an estimated 100-year global warming potential of about 10, meaning that its heat-trapping effect is about 10 times that of carbon dioxide.[39] Hydrogen leakage from end use applications should be mitigated through detection, monitoring, and prevention technologies, as well as regulation.

INFRASTRUCTURE BUILD-OUT

Another major concern with expanded hydrogen use is infrastructure build-out and its effects on land and local communities. With new applications of hydrogen in broader geographic regions, the infrastructure needed for production facilities and transport, especially pipelines, should be subject to strong permitting processes, environmental reviews, robust community engagement, and government regulations. In fact, there are many areas of regulation that energy regulators in particular should consider with regard to hydrogen, including electricity systems, gas systems, hydrogen pipeline and distribution networks, and safety.[40]

While many potential risks are discussed here, this report is not intended to be an exhaustive study of all non-climate environmental impacts of hydrogen. Further research is needed on other potential health and environmental impacts of hydrogen deployment, such as the toxicity of ammonia, impacts of ammonia combustion in the case of marine shipping fuel, and the indirect impacts on fertilizer usage.

SECTION 4: CONCLUSION AND RECOMMENDATIONS

HIGHLIGHTS:

- Hydrogen production must be low-emissions (less than 4kgCO_2e/kgH_2) and adhere to strong standards to achieve GHG emissions reductions in end-use sectors.
- The sectors analyzed in this study with the most climate benefits from clean hydrogen use are fertilizer, steel, and marine shipping.
- With competition for clean electricity, strategic deployment of hydrogen is essential for maximizing climate benefits. Hydrogen use should not be prioritized in sectors that have direct electric alternatives.

This analysis shows that it is incredibly important to produce hydrogen cleanly, adhering to strong emissions standards, to ultimately reduce emissions in end-use sectors. In fact, many production pathways touted as clean, including natural gas–based pathways and electrolysis using the current grid mix, still produce significant emissions, sometimes even increasing net life-cycle emissions compared with incumbent fossil fuel technologies.

However, clean hydrogen production is not sufficient on its own for successful hydrogen deployment. It must also be deployed strategically, only where it leads to emissions savings and in applications without an electrification alternative. Even the cleanest hydrogen carries widely varying levels of positive or negative climate impacts when deployed in different end uses.

As for end-use sectors with promising decarbonization benefits, hydrogen is a good option for industries like fertilizer, steel, and marine shipping, where there are no viable direct electrification alternatives. Conversely, hydrogen is not a good option for decarbonizing light-duty vehicle road transport, residential heating, or baseload power generation, as it is one-fifth to one-half as efficient as direct electrification and, in some cases, can cause unnecessary air pollution from combustion.

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These conclusions can be used to inform national and regional hydrogen policy, especially as governments revise hydrogen policy developed in recent years. Key recommendations for policy based on this analysis include the following: 1) Robust standards for what qualifies as clean or low-emissions hydrogen production are critical to minimize risks of emissions increases from hydrogen use relative to incumbent technologies; and 2) subsidies in the form of end-use tax credits or contracts for differences, for example, can support hydrogen end uses that maximize climate benefits in high-value sectors. Other types of policies, including additional financial incentives, market-based mechanisms, and regulations, are also important to drive demand for hydrogen in strategic end uses.

Ultimately, this study shows that hydrogen is not a universal climate solution but can be beneficial in targeted end uses. Policymakers should pursue a comprehensive set of policies that not only support production technologies but also drive demand in high-value end uses to ensure hydrogen has actual climate benefits.

APPENDIX: METHODOLOGY

1. OVERARCHING ASSUMPTIONS

- Throughout this analysis we consider "current grid" as one of the pathway inputs. This is intended to represent an average grid emissions intensity as predicted by the U.S. Energy Information Administration (EIA) for the year 2026. We used an EIA 2026 grid from its 2023 Annual Energy Outlook (AEO) with 53 percent fossil resources and 47 percent carbon-free resources including renewables, hydro, and nuclear power.
- This analysis uses Argonne National Laboratory R&D Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model. R&D GREET is an open-access life-cycle analysis (LCA) model used to evaluate life-cycle GHG and pollutant emissions, energy use, and water use of energy and transportation technologies. It is frequently used by researchers, analysts, and policymakers.
- In all the SMR pathways, we chose 1 percent natural gas leakage rates prior to the SMR process as the best-case scenario. This study's LCA does not account for areas where additional improvement could be made through renewable natural gas (RNG) or responsibly resourced gas. A rate of 1 percent represented a reasonable average best-case scenario and is the default rate in the GREET model used.
- All emissions impacts are based on a 100-year global warming potential (GWP).
- All units with "t" are metric tons.

2. NATURAL GAS-BASED PRODUCTION EMISSIONS BREAKDOWN

- The emissions breakdown of SMR and SMR CCS pathways is based on data from a 2024 study published in *Nature Energy*.[41]
- Upstream natural gas emissions include production and drilling, processing, and transmission, which are based on a 1.25 percent methane leakage rate and GWP-100. The grid emissions intensity for this breakdown is assumed to be 0.55 kgCO_2e/kWh.
- The 60 percent CCS case represented in Figure 3 is based on data for the pre-combustion capture only scenario (see the *Nature Energy* study's Supplementary Information, Figure 3). The 90 percent CCS case is based on the observed pre- and post-combustion capture scenario (see the *Nature Energy* study's Supplementary Information, Table 9).

3. FERTILIZER

- Ammonium nitrate (nitrogen-based fertilizer) was used for analysis purposes. Nitrogen-based fertilizer usage constitutes approximately 59 percent of all fertilizer used in the United States, and remaining fertilizer usage is potassium- or phosphate-based.
- Ammonia is a necessary feedstock for ammonium nitrate fertilizers. Other inputs include electricity, nitric acid, and natural gas.
- Ammonia is produced through the Haber-Bosch process, which involves reactions between hydrogen and nitrogen at high temperature and pressure.
- Different scenarios of ammonia production were analyzed based on emission intensity of the hydrogen component.
- Scenarios for electricity consumption (current grid, 80 percent clean, and 100 percent clean electricity) were used for analysis.
- Emissions in metric ton CO_2e were analyzed per ton of fertilizer produced. Different production pathways of ammonia, based on hydrogen production routes, were used to compare emissions.
- The GREET model limits the adjustment of capture rates for blue ammonia production. The model is set with a capture rate of 60 percent CO_2 emissions, and this study evaluated 1 percent upstream leakage.
- N_2O GHG total is constant across all cases shown. The differences among all cases are due to methane and CO_2 emissions.
- Nitrogen-based fertilizers can also have significant end-of-life GHG emissions that occur during their application on farmland in the form of N_2O emissions; however, these are outside the scope of this analysis.
- Efforts to reduce fertilizer use and overuse are important for both environmental and climate reasons. For climate, reduced fertilizer use implies fewer emissions from the production phase.

4. STEEL

- ERM used the following scenarios based on discussions with NRDC for estimating emissions related to steel manufacturing:
  - Blast furnace—basic oxygen furnace (BF-BOF): baseline case
  - Direct reduction of iron (DRI) with 100 percent natural gas
  - DRI with 100 percent hydrogen

- Scenarios were compared for methane-based hydrogen (gray and blue with 1 percent, 2.3 percent, and 3.5 percent methane leakage rates) and electrolytic hydrogen using different grid emission intensities (current grid, 80 percent clean, and 100 percent clean).
- The analysis boundary for the DRI process in this study includes steel production with an additional electric arc furnace (EAF) process step.

5. MARINE SHIPPING FUELS

- The baseline fuel used for comparison was heavy fuel oil (HFO), which was assumed to be burned in the main propulsion engines, auxiliary generator engines, and auxiliary boiler to produce the ship's steam.
- A roll on/roll off (Ro-Ro) shipping vessel was used for analysis purposes as a representative average in shipping. A Ro-Ro constitutes a mid-size shipping vessel used for delivery of automobiles.
- A Ro-Ro has three distinct operating modes: transiting, maneuvering, and docked operation. During transiting and maneuvering, all main and auxiliary engines and boilers are running. During docked operation, only the auxiliary generators and boiler are operating.
- For transiting, an average trip length of 4,988 nautical miles was assumed (distance from Port Nagoya in Japan to Port of Los Angeles in California) at an average speed of 18 knots.
- It was assumed that Ro-Ro vessels make an estimated 145 port calls to the Port of Los Angeles.
- Maneuvering was assumed to take four hours at an average speed of seven knots.
- Docked operation was assumed to take 30 hours.
- A study performed by the California Resources Board in May 2011, "Emissions Estimation Methodology for Ocean-Going Vessels," was used to inform assumptions around engine load, average vessel characteristics, and HFO emission factors.[42]
- Total emissions in metric tons CO_2e were analyzed.
- Different production pathways of ammonia, based on hydrogen production routes, were used to compare emissions.
- Ammonia-Specific Assumptions
    - Very little information on ammonia combustion engines is available. Current literature states that N_2O represents the main GHG source, along with NOx from combustion of ammonia. Based on a study performed by the Maersk McKinney Moller Center for Zero Carbon Shipping, it was assumed that N_2O emissions would be 0.06 g/kWh.[43]
    - Ammonia is produced through the Haber-Bosch process, which involves reactions between hydrogen and nitrogen at high temperature and pressure.
    - Different scenarios of ammonia production were analyzed based on emission intensity of hydrogen.
- Scenarios for electricity consumption (current grid, 80 percent clean, and 100 percent clean electricity) were used for analysis.
    - The value for emissions in tCO_2e for the present grid electrolytic ammonia scenario was amended by NRDC after ERM's analysis due to lack of supporting data for this scenario. The value used in this analysis is derived from the percentage difference between baseline gray hydrogen production and present grid electrolysis hydrogen production (~+50 percent), and this percentage is used in relation to emissions from gray ammonia production (~ 286,00 tCO_2e).
- As with the fertilizer scenario, the GREET model limits the adjustment of capture rates for blue ammonia production. The model is set with a capture rate of 60 percent CO_2 emissions, and this study evaluated 1 percent upstream leakage.
- Per the EPA, heavy fuel oil has a GHG emissions factor of 73–75 kg CO_2/MMBtu, which is ~10 tons CO_2/gallon (reported in the Emission Factors for Greenhouse Gas Inventories).
- Fuel conversions in this analysis:
    - Based on energy content, equivalent volumes of fuel are 22.8m gallons HFO and 42.4m gal. NH_3; almost twice as much NH_3 is required to fuel the vessels over the HFO baseline.

6. ROAD TRANSPORT

- Total annual CO_2e emissions were determined:
    - Well-to-pump emissions for E10 (GREET model)
    - Tailpipe emissions from gasoline (E10)
- Assumptions to determine tailpipe emissions:
    - Average fuel economy: 25 mpg
    - Average miles driven per year: 12,000
    - EPA emission factor: 9 kg CO_2 per gallon of gasoline
- A light-duty vehicle distribution of 80 percent light-duty trucks and 20 percent passenger cars was used to determine net methane and N_2O emissions.
- Assumptions for light-duty battery electric vehicle (BEV) and fuel cell electric vehicle (FCEV):
    - BEV efficiency (kWh/mile): 0.3
    - FCEV efficiency (kg/mile): 0.025
    - Average miles driven per year: 12,000
- GREET data for electricity emission factors were used to determine resulting emissions from the three scenarios:
    - Current grid electricity
    - 80 percent clean electricity
    - 100 percent clean electricity

7. POWER GENERATION

- The emission intensities for hydrogen production routes were used to estimate the emissions associated with using an equivalent amount of fuel in a 1 GW combined cycle gas turbine (CCGT) power plant (nameplate capacity).
- Total heat content of natural gas fuel was determined that would be required to produce 655 MW of actual net power output (using an example commercially available plant heat rate and plant power output).
- The initial total volume of fuel (in standard cubic feet of natural gas) was determined based on required heat content.
- The volume of natural gas and hydrogen was estimated based on the blend ratios.
- Within the LCA models, the blended fuel net energy content decreased compared with the baseline scenario (resulting in reduced power output) due to reduced energy content of the hydrogen/natural gas blend. To adjust for this, emissions were scaled proportionally to provide equivalent power output to the baseline scenario.
- 100 percent clean electricity source to create electrolytic hydrogen for power generation has no GHG emissions within the LCA.
- The GREET model default for upstream leakage in power generation was 0.8 percent leakage. In this study, we overrode the percentage to 1 percent for the CCGT baseline for consistency with the other baseline scenarios.

8. RESIDENTIAL HEATING

- In the residential heat use cases, we considered a level playing field, where a homeowner had a choice between a modern gas furnace and an air source heat pump without the need to retrofit the home.
- Heat input of fuel was determined based on required energy (MMBtu) to heat an "average" residential home on an annual basis (based on publicly available data, such as EIA and the U.S. Census Bureau).
- EIA 2020 Residential Energy Consumption Survey (RECS) data were used for determining the size and cost of a modern gas furnace system and heat pump capable of equivalent performance using national average–level data. This is the most recent RECS available through EIA as of August 2025.
- A single-family home with a heating load of 46 MMBtu/year for a gas furnace and the equivalent 4,300 kWh for an air source heat pump (ASHP) on a national basis was used for analysis.
- Using annual efficiency factors for natural gas furnaces (95 percent) and ASHPs (300 percent), required input energy to each appliance was determined (MMBtu for gas; kWh for ASHP)
- Based on blending ratios of hydrogen and natural gas, volume of fuel (in standard cubic feet) was determined from the total required heat input to operate a gas furnace.
- Using emission intensity values for hydrogen pathways and the electric grid, total annual emissions under each blending scenario were compared with a modern natural gas furnace and an ASHP with three grid emissions scenarios: current grid, 80 percent clean grid, and 100 percent clean grid.

ENDNOTES

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