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HYDROGEN: WHAT GOOD IS IT?

A technical exploration of the potential of hydrogen to contribute to a decarbonized energy system

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Preface

In 2021 and 2022, the federal government passed far-reaching laws on infrastructure and climate, with deep implications for the energy transition that is widely recognized as an urgent and necessary element to mitigate climate change damage. Major federal investments are envisioned (and are being made) in a variety of energy technologies and sources, including for using hydrogen as an energy source.

Hydrogen is not generally used as an energy source today because it is made from fossil fuels, mainly natural gas; it is cheaper to simply burn the fossil fuel. It is being considered seriously today because it does not emit carbon dioxide (CO_2), the principal anthropogenic greenhouse gas, when so used.

The focus of this study is to examine whether hydrogen as an energy source can significantly reduce warming impact when it displaces fossil fuels and, if so, under what circumstances and how much. As with any other energy source, whether primary – derived from nature (whether renewable or not) – or secondary (made from another energy source), producing hydrogen has significant environmental impacts. This makes the issue of net impacts important. There are environmental justice implications. These are identified but not explored in detail in this initial work, since the subject is vast. The plan is to seek the advice of environmental justice leaders and experts, convened by Just Solutions, the organization that commissioned the Institute for Energy and Environmental Research to produce this report. Once the environmental justice priorities are identified, more detailed work on those issues is expected.

Thus, the present report is narrowly focused, exploring hydrogen production, storage, transport and use. Its scope includes technical aspects and opportunity costs. For instance, the use of "green" hydrogen, made from water (H_2O) using renewable energy, would result in zero CO_2 emissions if used in a transit bus or car. But is it better to electrify transportation using hydrogen or use more efficient batteries? All other things being equal, using renewable electricity directly is more efficient – and renewable energy will go farther in decarbonization in that mode rather than via hydrogen. But other things are not always equal. Electricity may be unsuitable as an energy source in a particular application, given available technology.

In sum, we explore the technical nooks and crannies as well as the big picture of hydrogen as an energy source. This approach leaves out a lot of context, which we wish to note here. For instance, efficiency is widely recognized as essential to a sound energy transition in the United States and worldwide; it is not considered systematically here, though we discuss its importance in some specific cases. We have briefly illustrated the need for a broader analysis of the energy and environmental justice context with a few examples of possible alternatives to hydrogen use.

We have not considered overall sustainability of energy use, the lack of which is at least partly connected with a business-as-usual approach of simply substituting zero carbon energy sources for fossil fuels. Additionally, ecosystems are under severe pressure from multiple directions including, but not only, from climate extremes and global temperature rise. Another major issue is global equity: the wealthiest 1% are responsible for twice the carbon emissions that the poorest 50%,[1] and there are serious inequalities within many countries. The vastly disproportionate impacts of mining and extraction of materials and fuels have often fallen on the very same people who have benefited least from the use of fossil fuels.

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[1] Oxfam 2023

Given this history, should the mineral resources, like resources needed for the energy transition, be extracted and distributed in a similarly inequitable way? Will these resources become focal points for conflict (as oil has been for a century)? Indeed, they already are in some cases. So far as climate is concerned, can zero emissions be achieved in time if inequity is not mitigated substantially and rapidly – remembering that the United States, the European Union and Japan emit less than one-third of the world's greenhouse gas emissions?[2]

Despite these limitations, we believe this report points to ways in which hydrogen can be used and, as importantly, ways in which it should not be used to further climate goals. Useful applications of hydrogen include using it to produce steel from iron ore and making it from renewable energy that would otherwise be curtailed for a larger array of uses. In some cases, using hydrogen could be counterproductive for climate and contribute to inequity. A prime example is mixing hydrogen with natural gas in existing infrastructure.

A word about net impacts and site-specific impacts. When hydrogen (or any other zero CO_2 emissions source) displaces fossil fuels, it makes new demands on some resources. For example, iridium and platinum are currently indispensable catalysts for electrolysis of water. At the same time, the impacts from fossil fuel production and the entire mining and industrial infrastructure for producing, transporting, and using them will be reduced. Considering the net global balance is important.

At the same time, the site-specific impacts are also critical. For example, the harm in a community where the land is ripped up for a new mine can't be simply written off because an equal or even greater harm is avoided elsewhere. We discuss these matters to some extent in this report, but a comprehensive assessment in the context of the energy transition is needed.

Water resources exemplify this issue well. Large amounts of water are needed for hydrogen production (Chapter IV). But water resources will also be liberated as the United States as the world moves away from the use of steam turbines driving electric generators to produce electricity ("thermo-electric generation"): the dominant mode of electricity generation today. How will the liberated water resources be used? By whom? How will water resource issues be taken into account in siting hydrogen production? And will hydrogen production become subject to the increasing extremes of weather, resulting in a less resilient energy system? The energy transition provides the opportunity to increase resilience and equity in the energy, water, and material production systems. We have analyzed the water question in some detail to provide an overall quantitative aspect needed for an exploration of water justice and water supply resilience questions.

The report begins with a summary in Chapter I that includes the highlights of this report's analysis as well as its main conclusions and the technical recommendations that arise from the analysis. Then, Chapter II introduces hydrogen, its significant role in the present economy as a chemical commodity, and

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[2] The United States, European Union, and Japan are responsible for the vast majority of cumulative emissions. Their cumulative emissions amount to about 800 billion metric tons of CO_2, compared to about 200 billion metric tons for China and they have a smaller combined population than China. India's cumulative emissions are about 50 billion metric tons. (Emission numbers are rounded.) Though China is now the world's largest annual emitter in terms of total CO_2, its per person emissions are still about half those of the United States. In recognition of the disproportionate impact wealthy countries have caused, the foundational climate treaty – the 1992 United Nations Framework Convention on Climate Change – requires them to take correspondingly larger responsibility for mitigation.

its envisioned role as an energy source. Next, Chapter III addresses the climate impact of hydrogen in the atmosphere. While hydrogen is not a greenhouse gas, it exerts a warming impact indirectly even at current levels of use. These impacts could increase significantly at projected hydrogen usage levels over the next few decades. Chapter IV explores the various methods of hydrogen production. Here we estimated the greenhouse gas emissions associated with each production method and compared them to the draft Department of Energy guideline for “clean hydrogen”. Water use is also estimated in some detail in Chapter IV as are mining and processing impacts for electrolysis. Naturally occurring hydrogen may exist in economically significant amounts; this issue is mentioned for completeness, since it could change role that hydrogen plays in decarbonizing the system.

Chapter V discusses the methods to store and transport hydrogen for different applications. Chapter VI explores different potential uses of hydrogen, including the principal ones discussed in the Department of Energy’s draft hydrogen strategy. The net impact of making and using hydrogen in various ways to displace fossil fuels is evaluated. Using green hydrogen for some purposes, like steel and ammonia production, would significantly reduce greenhouse gas emissions. In other cases, notably mixing hydrogen with natural gas in pipelines for use in building heating, the climate benefit would be small (with green hydrogen) or even negative, with grey or blue hydrogen. Chapter VII outlines the environmental justice and safety issues that emerge from the technical exploration. Finally, we have included a few examples the importance of considering low-carbon and low-impact alternatives to hydrogen before adopting hydrogen as the preferred approach for mitigating greenhouse gas emissions for a particular end use such as container cargo shipping fuel. Such an examination should be carried out more generally given the cost, water intensity, and materials-related environmental justice impact of hydrogen.

We deeply appreciate the confidence that Just Solutions and its Executive Director Aiko Schaefer have placed in the Institute for Energy and Environmental Research (IEER) in asking it to produce this report on a critical subject. We are also very thankful to Breakthrough Energy Foundation for funding this work, via Just Solutions, and to Ani Kame’enui, the Program Officer at Breakthrough Energy for research materials and for the reviews and comments on this work in the course or its preparation. We have benefited from many useful comments and suggestions from members of the Just Solutions Research Collaborative that have materially improved the scope and content of the report. The Research Collaborative was appointed by Just Solutions to develop an environmental justice framework for energy transition technologies and to review the reports being prepared by IEER for Just Solutions as part of the Breakthrough Foundation grant. That framework for hydrogen has been prepared and will be published independently of this report. This report has benefited greatly from reviews by Dr. Matteo Bertagni, Dr. Elena Krieger, Adria Wilson and Dr. Dimosthenis Sokaras. However, we alone, as the authors, are responsible for any errors that remain and, more generally, for the analysis, conclusions, and recommendations in this report.

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List of Abbreviations

AEM: anion-exchange membrane
BE8: battery electric class 8 truck
BF-BOF: blast furnace, basic oxygen furnace
Btu: British thermal unit
°C: degrees Celsius
CCS: carbon capture and storage *or* carbon capture and sequestration
CCUS: carbon capture, utilization and storage *or* carbon capture, utilization and sequestration
CO_2-eq: CO_2-equivalent
DOE: United States Department of Energy
EAF: electric arc furnace
EJ: environmental justice
°F: degrees Fahrenheit
FC8: fuel cell class 8 truck
GHG: greenhouse gas
GWP: global warming potential
H-DR: hydrogen-based direct reduction
HFC: hydrofluorocarbon
IEER: Institute for Energy and Environmental Research
kWh: kilowatt-hour
MDPE: medium-density polyethylene
MWh: megawatt-hour
NMHC: non-methane hydrocarbon
PEM: proton-exchange membrane
PM2.5: fine particulates with a diameter below 2.5 micrometers
ppm: parts per million
psi: pounds per square inch
SMR: steam methane reforming
UHS: underground hydrogen storage
YSZ: yttria-stabilized zirconia

List of Chemical Formulas

CO: carbon monoxide
CO_2: carbon dioxide
CO_3^{2-}: carbonate ion
CH_4: methane
e^-: electron
$H^\bullet$: hydrogen radical
H^+: hydrogen ion, more commonly referred to as ‘proton’
H_2: dihydrogen, more commonly referred to as ‘hydrogen’ or ‘molecular hydrogen’
H_2O: water
$LiAlO_2$: lithium aluminate
N_2: dinitrogen, more commonly referred to as ‘nitrogen’ or ‘molecular nitrogen’
NH_3: ammonia
N_2O: nitrous oxide
NO: nitric oxide
NO_2: nitrogen dioxide
NO_x: nitrogen oxides, referring to mixtures of nitric oxide and nitrogen dioxide
O_2: dioxygen, more commonly referred to as ‘oxygen’ or ‘molecular oxygen’
O_2^-: oxide ion
O_3: ozone
$OH^\bullet$: hydroxyl radical
OH^-: hydroxide ion
SiC: silicon carbide
SO_2: sulfur dioxide

Glossary

Anion: an atom or molecule with one or more additional electrons. Because of their extra electrons, anions carry a negative charge.

Anode: the side of an electrochemical device where molecules are oxidized (see ‘oxidation’ below). In an electrolyzer, the anode converts water to oxygen gas. In a fuel cell, the anode converts hydrogen gas to water or protons. (See also ‘cathode’ below.)

Anthropogenic: caused by humans.

Capacity factor: a metric that relates the actual electrical output of an electricity plant over a specified period of time (usually one year) to the output if it operated at its design (or “nameplate”) capacity for that same period. For example, a one-megawatt plant would generate 8,760 megawatt-hours if running at full capacity over one year. If it actually generates 7,000 MWh over that same time period, it would be operating at a capacity factor of 80%. Capacity factors also apply to devices like electrolyzers. In this case, they relate the actual hydrogen output of an electrolyzer to their rated output over a period of time.

Cathode: the side of an electrochemical device where molecules are reduced (see ‘reduction’ below). In an electrolyzer, the cathode converts water or protons to hydrogen gas. In a fuel cell, the cathode converts oxygen gas to water. (See also ‘anode’ above.)

Coke: a fuel that is obtained by heating coal in the absence of oxygen. This process is called ‘coking’ and often emits dangerous levels of air pollution that impact workers and communities near coking plants. Coke is an input for conventional steelmaking processes to convert iron ore into raw steel (called ‘pig iron’).

Curtailment: the deliberate reduction of electricity generation when generation exceeds electricity demand, usually in an unplanned way. Curtailment of wind and/or solar electricity occurs when their output is high relative to demand and output of other resources like nuclear power plants cannot be quickly or easily reduced. This electricity could be used if demand is added to the system – for instance by charging batteries or producing electrolytic hydrogen.

Cryogenic: a process happening at very low temperatures. In the context of this report, the word ‘cryogenic’ refers to cooling hydrogen gas to temperatures far below the freezing point of water, in order to turn the hydrogen gas into a liquid.

Electrolysis: the process of breaking apart molecules by using electricity. In the context of this report, water (H_2O) is split into hydrogen (H_2) and oxygen (O_2) molecules.

Electrolyzer: a device that performs electrolysis (see above).

Fuel cell: a device that turns fuels into electricity. In the context of this report, fuel cells combine hydrogen (H_2) and oxygen (O_2) molecules into water (H_2O), while simultaneously releasing electricity.

Global warming potential: a measure that compares the heat-trapping effect of an atmospheric gas averaged over a specified period of time to the heat-trapping effect of carbon dioxide (CO_2) set equal to 1 over that same time. The global warming potential expresses how many kilograms of CO_2 would be required to achieve the same warming impact as a kilogram of another gas over the specified time. For example, the 20-year global warming potential of methane (CH_4) is 82.5, which means that 82.5 kilograms of CO_2 would achieve the same warming impact as one kilogram of methane over 20 years. Thus, methane is a much stronger greenhouse gas than carbon dioxide. Because different gases have different lifetimes in the atmosphere, the global warming potential depends on the time span across which it is evaluated. For example, the 100-year global warming potential of methane is29.8, which is 2.77 times lower than the 20-year global warming potential value of 82.5. This means that the relative warming impact of methane decreases over time. (See also 'radiative forcing' below.)

Half-life: the half-life is the time it takes for a radioactive element to decay by emitting radiation to the point that its radioactivity is half the initial amount. . See also 'Lifetime' below.

Induced seismicity: seismicity (see below) caused by human activity, such as by injecting water underground that has been produced in the course of hydraulic fracturing.

Lifetime: The time is takes for a chemical emitted at a point in time into the atmosphere to dissipate to 37% of its original amount. Lifetime is similarly defined for radioactivity: it is equal to 1.44 times the half-life.

Lock-in: The phenomenon that (fossil-fuel) infrastructure is difficult to shut down prior to the intended period of operation when the asset was built. For example, power plants or factories have a typical economic lifetime. Their operators will want to operate these plants for that entire period, in order to achieve the planned economic returns. When assets are regulated, like natural gas distribution pipelines, owners are guaranteed a return on investment over a period of time. This creates a "lock-in" of that infrastructure for that period. If forced to shut down, for instance for limiting carbon emissions, the undepreciated portion of the plant becomes a stranded asset (see below).

Molar: mole-based amounts of a substance. For example, a kilogram of water contains 55.6 moles of water. (See 'mole' below.)

Mole: a unit for measuring amounts of substances. A mole is equal to 602 trillion billion molecules or atoms of a given substance.

Opportunity cost: the concept that, if you decide to do one thing, you cannot do another. For example, one may choose to either invest a billion dollars in electric vehicle subsidies or in building out a public transit network. If, in this situation, one chooses electric vehicle subsidies, the opportunity cost is the public transit build-out that could have happened instead. The concept of opportunity cost is used to compare the consequences of alternative investments, including for their climate impact.

Oxidation: when a molecule loses electrons, it is oxidized. For example, in a fuel cell, hydrogen (H_2) loses its electrons to become protons (H^+). Thus, the hydrogen is oxidized. (See also, 'reduction' below.)

Proton: a hydrogen atom that is missing an electron. Protons carry a positive charge and are denoted as: H^+.

Radiative forcing: a measure of how much heat an atmospheric greenhouse gas traps and radiates back to Earth. Radiative forcing is expressed in units of watts per square meter (W/m^2) of the Earth's surface.

Reduction: when a molecule gains electrons, it is reduced. For example, in an electrolyzer, protons (H^+) are given electrons to become hydrogen (H_2). Thus, the protons are reduced. (See also, 'oxidation' above.)

Roundtrip efficiency: a measure that quantifies how much energy is maintained when storing and releasing energy. For example, the charging energy of a battery may be 90%, which means that 10% of the energy is lost while charging. Its discharging energy may also be 90%, meaning that an additional 10% of energy is lost while charging. One can find the roundtrip efficiency by multiplying both efficiency values. In this example, the roundtrip efficiency equals 90% times 90%: 81%.

Seismicity: the probability of occurrence of earthquakes in an area. These can be naturally occurring due to normal movement in the earth's crust. However, earthquakes can also be caused by human activity. (See 'induced seismicity' above.)

Steam methane reforming: the process of converting methane (CH_4) and water (H_2O) into hydrogen (H_2) and carbon monoxide (CO). This process is typically paired with the water-gas shift reaction, which reacts the CO with another water molecule to produce carbon dioxide (CO_2) and additional H_2.

Stranded asset: a piece of property (often infrastructure) that is shut down before its maximum economic lifetime. Stranded assets can result in financial losses for ratepayers, taxpayers, shareholders, or some combination. (See also 'lock-in' above.)

Stratosphere: the second layer of the atmosphere above the Earth's surface, which starts at 10 kilometers (6.2 miles) to 15 kilometers (9.3 miles) above it and ends around 50 kilometers (31 miles) above the Earth's surface. (See also 'troposphere' below.) The next layer above is the 'ionosphere'.

Tailings: waste that occurs when the valuable fraction of a metal ore is separated from the fraction that is not sought as a commodity. Tailings can often contain toxic or environmentally harmful compounds. For example, the tailings from copper and nickel mining can contain iron sulfides, which can acidify soils; metal mine tailings also often contain radioactive elements like uranium, thorium and radium, even if the desired element in the ore is not radioactive.

Thermo-electric generation: electricity that is created by burning a fossil fuel and/or heating water in order to spin a generator that produces electricity. Also called 'thermal generation'.

Thermolysis: the process of breaking apart molecules by using heat. In the context of this report, water (H_2O) is broken into hydrogen (H_2) and oxygen (O_2) molecules.

Troposphere: the bottom layer of our atmosphere, which starts at the Earth's surface and ends around 10 to 15 kilometers (6.2 to 9.3 miles) high. (See also 'stratosphere' above.)

Water consumption: all water that is used up in a process like electricity or hydrogen production. In the context of hydrogen production, this includes water (H_2O) that is split up into hydrogen (H_2) and oxygen (O_2). In addition, it includes water that is lost due to evaporation in the process of condensing steam back into water in thermo-electric generation. Consumed water is all water that was withdrawn from a source but not returned to it. (See also 'water withdrawal' below.)

Water withdrawal: all input water for a process like electricity or hydrogen production that is withdrawn from a source (such as a river or lake). By definition, water withdrawal equals the sum of water that is consumed in a process and the water that is discharged, usually back to its source. (See also ‘water consumption’ above.)Anion: an atom or molecule with one or more additional electrons. Because of their extra electrons, anions carry a negative charge.

I. Summary[3]

Hydrogen is a major chemical commodity in the United States and the world, used largely in petroleum refining and to make ammonia and other chemicals. It can be used as a fuel, but apart from niche uses, it currently is not so used. That is mainly because, unlike natural gas, petroleum, wind energy, or solar energy, hydrogen is not a primary energy source. Instead, it must be made from one. That primary fuel is mostly natural gas (95% in the United States, 75% globally), with almost all the rest being coal. This conversion step from primary fuels makes hydrogen a relatively expensive energy source: it is generally cheaper to just use the primary fuel. The exception to this statement is natural underground geologic hydrogen, but it is unclear whether this hydrogen exists in quantities that are relevant to the energy transition.

Hydrogen has come to the fore in recent years as an energy source because it emits no greenhouse gases when used as such. Even so, there are two caveats to its potential to contribute to a decarbonized energy system:

- There must be no greenhouse gas emissions in the production of hydrogen from a primary energy source;
- Leaks of hydrogen, the lightest gas, must be kept minimal because hydrogen in the atmosphere has an indirect warming impact – a factor that is so far absent from the proposed definition of "clean hydrogen", at least in the United States.

Main recommendations

1. **The climate impact of hydrogen leaks** and the use of a 20-year warming potential of hydrogen and methane must be incorporated into the "clean hydrogen" standard, to accurately assess the climate impacts of hydrogen and methane leakages when hydrogen is used as an energy source.
2. **Carbon-free electricity supplying existing loads** should not be diverted for hydrogen production.
3. **No new hydrogen production from fossil fuel feedstocks** should be permitted or supported.
4. **Water equity and justice issues** should be fully integrated into hydrogen policies and decision-making.
5. **The use of curtailed renewables** for green hydrogen production should be incentivized and safety issues with intermittent production should be addressed with high priority with due attention to safety issues.
6. **Local and global environmental justice issues** should be fully addressed in their local aspects, as well as in the net system balance addressing the benefits of displacing fossil fuels.

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[3] References show in the main text are not repeated in the summary. Unless mentioned, 20-year global warming potentials for methane and hydrogen are used since the time frame for achieving net-zero greenhouse gas emissions is the year 2050.

Main findings

1. **Hydrogen leaks** have an indirect warming impact; if not minimized they could negate much or all of the climate benefit of using hydrogen.
2. **Blue hydrogen** – made from natural gas with CCS – does not meet the DOE "clean hydrogen" guidance. Blue hydrogen increases net atmospheric methane pollution when replacing fossil fuels Btu-for-Btu unless hydrogen leaks are kept very low and methane leaks are reduced by about two-thirds.
3. **Diverting carbon-free electricity from existing loads** to produce hydrogen results in a net CO_2 emissions increase, since fossil fueled electricity will generally be needed to replace a portion of the diverted electricity. In most cases, the resulting net emissions per unit of hydrogen production are higher than emissions from fossil-fuel-based hydrogen production, including grey hydrogen.
4. **The water intensity** of hydrogen production is a major concern and a siting constraint; it raises major water equity and justice issues.
5. **Green hydrogen used strategically** presents major opportunities for decarbonizing the energy system including in making steel and in a variety of uses when made from renewable electricity that would otherwise be curtailed.
6. **Major environmental justice issues are associated with hydrogen** as an energy source, both local and global. **There are also environmental benefits** when hydrogen reduces fossil fuel use, such as the reduction of fracking and associated pollution.

This study is an exploration of the technical potential of hydrogen to contribute to the mitigation of climate change. We summarize the findings in each chapter and highlight the conclusions here. Hydrogen has been assigned colors depending on the primary energy source used to produce it. This report mainly focuses on grey hydrogen (made by steam reforming of natural gas); blue hydrogen, which is grey hydrogen plus carbon capture and sequestration (CCS);[4] green hydrogen, made by splitting water electrochemically ("electrolysis") using renewable electricity sources; and pink hydrogen (made by electrolysis using nuclear electricity).

a. Hydrogen and climate

Hydrogen, though not a greenhouse gas itself, has a warming impact in three major ways:

1. It reacts with hydroxyl radicals ($OH^\bullet$): the main chemical cleansing species in the atmosphere. By reducing the availability of hydroxyl radicals, hydrogen leaks increase the atmospheric concentration of methane, a powerful greenhouse gas that is the main

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[4] We take CCS at face value for the purposes of climate impact estimation, even though CCS is a major environmental justice issue. It is a complex and critical issue in its own right. However, sidestepping CCS for the purposes of this climate-centered report does not significantly impact our analysis and conclusions, because blue hydrogen, exceeds the Department of Energy's "clean hydrogen" guidance and would not have a climate benefit in most uses. See Figure S-3 in this summary.

constituent of natural gas. This mechanism represents about 50% of hydrogen's warming impact.

2. It increases the amount of ozone in the troposphere (the lowest layer of the atmosphere). In this part of the atmosphere, ozone is a pollutant and a greenhouse gas, accounting for 20% of hydrogen's warming impact.
3. It creates water vapor in the stratosphere (the atmosphere layer above the troposphere) where water vapor is a greenhouse gas. This comprises about 30% of hydrogen's warming potential.

The total impact of these three mechanisms can be converted into a global warming potential (GWP). This metric represents quantifies how many kilograms of CO_2 would yield the same warming impact as one kilogram of hydrogen (or other greenhouse gas). We have used a 20-year warming potential of 33 in this report; for comparison, the 20-year GWP of methane is 82.5. Both measures are relative to a reference value of 1 for CO_2. At present, hydrogen attributable to human activities already has an impact of about 1% of total anthropogenic warming even before significant production and use as an energy source.[5]

Considering the climate impact of hydrogen is important, because hydrogen can leak during production, transport, storage and use; hydrogen leaks alone, if large enough, could cause warming impacts to exceed the guidance of the Department of Energy (DOE) for clean hydrogen – 4 kilograms of CO_2-equivalent (kg CO_2-eq) per kilogram (kg) of hydrogen.[6] Figure S-1 shows hydrogen leaks compared to this guidance: the DOE guidance would be exceeded at a leak level of 12%. Figure S-1 represents only the impact of leaks: the emission of other greenhouse gases when producing hydrogen are in addition to the impacts of leaks, so they would add to the climate impact. The need to minimize hydrogen leakage due to its climate impact has been recognized by the International Energy Agency, which has called for: "[e]ffective steps (…) to avoid hydrogen leakage".[7]

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[5] A kilogram is equal to 2.204 pounds. A metric ton – 1000 kilograms – is about 10% more than a U.S. short ton.

[6] A kilogram of hydrogen is roughly the energy equivalent of a gallon of gasoline.

[7] IEA 2022, page 158

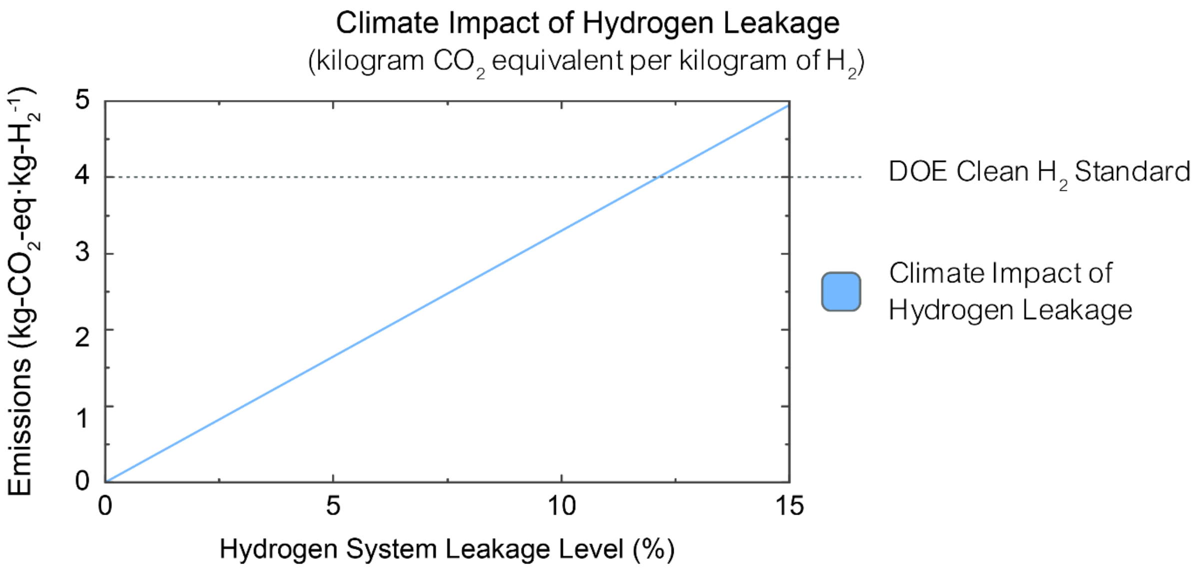

Figure S-1: Warming impact of hydrogen leaks compared to the DOE clean hydrogen guidance using a 20-year warming potential for hydrogen of 33.

When evaluating the usefulness of hydrogen as a climate solution, it is therefore essential to consider the overall balance of greenhouse gas emissions: one should consider hydrogen leaks, other greenhouse gas emissions from hydrogen production and the avoided greenhouse gas emissions when hydrogen displaces fossil fuels. Illustrating this point, Figure S-2 shows the change in atmospheric methane levels in a scenario where hydrogen replaces 15% of global fossil fuel use (on an equal energy basis) for green and blue hydrogen. Current levels of methane leaks from the natural gas system are about 2.7%. Figure S-2 shows that leaks must be reduced to about 1% if blue hydrogen is to be neutral regarding methane when displacing fossil fuels on a one-for-one energy basis. For a significant methane-related benefit, blue hydrogen-related methane leaks must be much less than 1% and hydrogen leaks must also be low. That equation changes if the efficiency of hydrogen use is much greater than that of the displaced fossil fuel (as is the case with steel production).

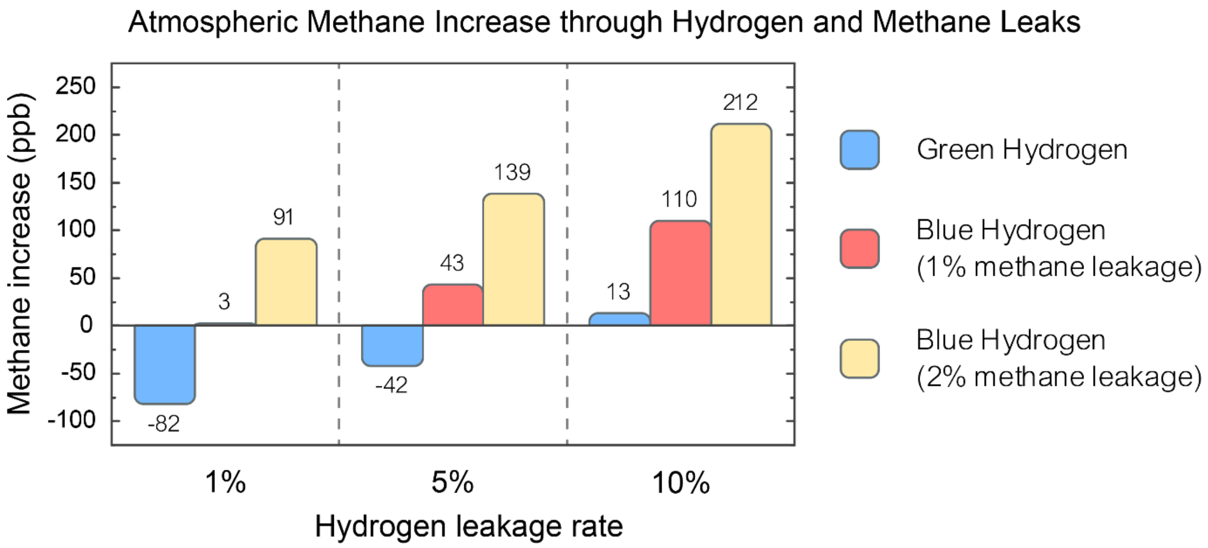

Figure S-2: Net change in global methane concentrations at three hydrogen leak rates and two methane leaks rates when hydrogen displaces about ~15% of global fossil fuel use.

Hydrogen and climate findings and recommendations

Findings:

1. Hydrogen leaks can have substantial warming impacts.
2. When also considering methane leaks, blue hydrogen can significantly decrease the benefit of displacing fossil fuels, even at low levels of hydrogen leaks except in cases where hydrogen use efficiency is much greater, so that much less than one Btu of hydrogen is required to displace a Btu of fossil fuel.
3. The DOE has not included the warming impact of hydrogen leaks in its clean hydrogen guidance.

Recommendations:

1. Keep hydrogen leaks throughout the hydrogen system low.
2. To actualize the potential climate mitigation benefits of hydrogen, the DOE and other government departments involved in setting clean hydrogen policy must include the 20-year warming impact of hydrogen.

b. Hydrogen production

i. Greenhouse gas emissions

The DOE's Argonne National Laboratory has estimated the greenhouse gas (GHG) emissions for various kinds of hydrogen production on a lifecycle basis, excluding the emissions associated with the manufacture of the capital equipment. This is a reasonable simplification, since roughly a similar amount fossil-fuel-related capital equipment would be avoided by implementing hydrogen. Argonne has also taken into account more relevant factors such as methane leaks, the energy for fuel production, and other sources of greenhouse gas emissions. In this report, we use the results of the Argonne modeling with one modification: Argonne uses only the 100-year warming potential for methane. In this report, we have estimated GHG emissions for both the 100-year and 20-year GWP but used the latter unless specifically mentioned. Argonne also uses a very high estimate for the capture rate of carbon capture and sequestration of 96%; this is not representative of the CCS experience in demonstrations other than using the captured CO_2 to stimulate oil production.

Figure S-3 shows the lifecycle GHG emissions for grey, blue, and green hydrogen production for methane leak rates of 1% and 2%; this assumes a reduction from the current national average leak rate of about 2.7%. When optimistically assuming methane (natural gas) leak reductions to 1%, producing blue hydrogen would not meet the DOE “clean hydrogen” guidance, even if hydrogen leaks are completely ignored. The guidance specifies a maximum of 2 kilograms of CO_2-eq emissions per kilogram of hydrogen at the production site and a “lifecycle” total maximum of 4 kg CO_2-eq the metric shown in Figure S-2.

The CO_2-eq values in Figure S-3 use the very high estimate of carbon capture in the Argonne model. A more realistic but still high value of 70% would mean that even with a 100-year warming potential for methane and 1% methane leaks, blue hydrogen would not meet the DOE clean hydrogen guidance. When hydrogen leaks are added, the picture deteriorates further.

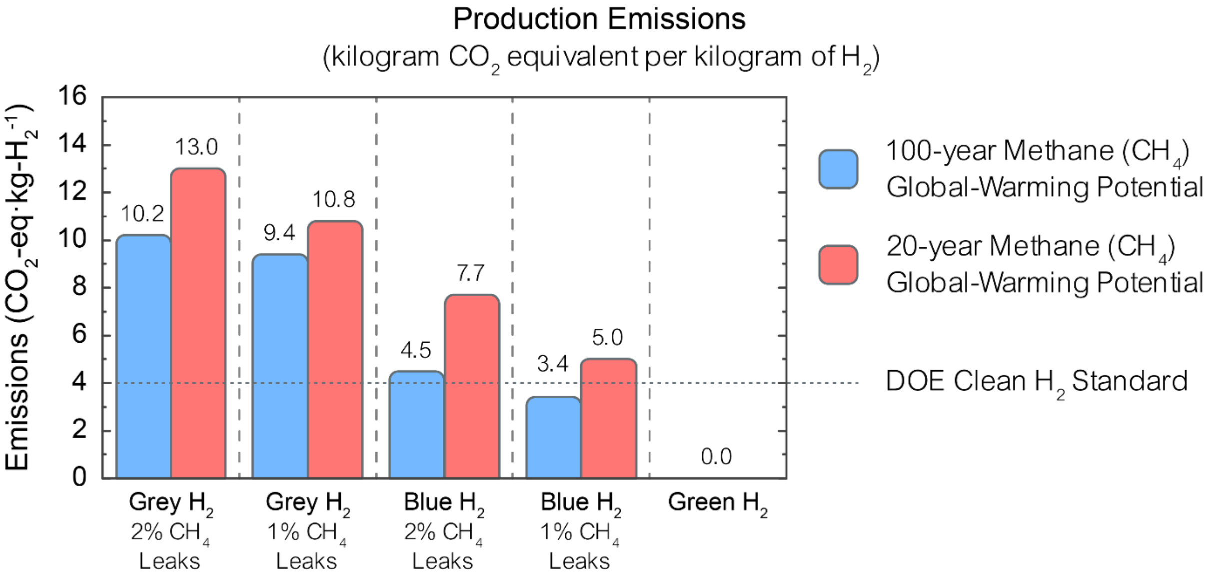

Figure S-3: CO_2-eq emissions per kilogram of hydrogen production for grey, blue, and green hydrogen at two methane leak levels. PEM is a specific electrolysis technology suited to intermittent operation. Hydrogen leaks are not included.

Green hydrogen easily meets the DOE’s clean hydrogen standard. Leaks at levels below 12% would not affect that conclusion. That would also be true of pink hydrogen, i.e., hydrogen made using nuclear electricity. There is, however, a major caveat. With very limited exceptions, the energy systems emissions impact of making green or pink hydrogen depends on whether new renewable or nuclear power plants are used or whether existing zero-emissions electricity is diverted to make hydrogen.

To exemplify the issue, we calculated the onsite and global impact of the small pink hydrogen pilot plant partly funded by the DOE at the Nine Mile Point nuclear power plant in New York. The onsite emissions of this plant are zero, because the electrolysis consumes electricity directly supplied by the plant. However, the hydrogen plant is a new load on the electricity grid, because the electricity used to supply it was previously used to meet demand in New York State. As a result, the electricity supplied to the hydrogen pilot plant would no longer be available to the households and businesses it previously supplied. This new supply deficit has to be made up by generation elsewhere, which includes both fossil fuel and zero-emission generation. Thus, the net impact on New York State's GHG emissions would be that non-zero emissions electricity replaces zero emissions electricity. The actual impact depends on the assumptions about the emissions profile of the replacement electricity. If it is the average of electricity sales in New York – which includes a large amount of in-state generation as well as imported hydropower, the net emissions in amount to about 18 kg CO_2-eq/kg hydrogen; this is considerably worse than the 14.6 kg CO_2-eq emissions for grey hydrogen at the current 2.7% methane leak rate. If natural gas plants that now operate at a low capacity factor supply the electricity, the emissions would rise to more than 40 kg CO2-eq per kg hydrogen.

The same reasoning would apply if existing wind, solar geothermal, or hydropower were diverted to make hydrogen; the specific impact per unit of hydrogen would be worse than New York in most places because New York has more zero-emission electricity in its usage profile than most other states. The exception to this for states like California and Texas, which now have occasional substantial surpluses of renewable electricity that are curtailed (i.e., not produced) because they are in excess of system demand. We estimate that curtailed renewable generation in California could produce about 34,000 metric tons of hydrogen per year. Curtailed renewables in Texas in 2022 could have produced about 150,000 metric tons of hydrogen.

The example above illustrates the concept of 'additionality': green/pink hydrogen are only truly zero-emissions if new electricity generation capacity is installed to produce the hydrogen. If additionality is ignored, then producing hydrogen would take clean electricity away from other applications, causing fossil-based electricity to ramp up elsewhere in the grid.

ii. Water use for hydrogen production

Beside generating carbon emissions, hydrogen (H_2) also requires water. It is made entirely from water (H_2O) when water is split into hydrogen and oxygen. Grey and blue hydrogen get half of their hydrogen atoms from water (steam) and half from the hydrogen in methane (CH_4). These theoretical minimum water requirements are generally substantially exceeded since hydrogen production requires very pure water inputs. This water is produced by purifying 'raw' water, which results in a stream of rejected water with higher concentrations of salts; this rejected water may be useful for other applications, or not, depending on salt concentration. In addition, hydrogen produced by electrolysis requires large amounts of electricity. When the electricity is supplied by thermo-electric generation, the cooling water requirements for the electricity considerably exceed the direct water inputs needed for hydrogen production. Figure S-4 shows a schematic of thermo-electric generation; coal-fired power plants and many natural gas-fired power plants have the same scheme of water use.

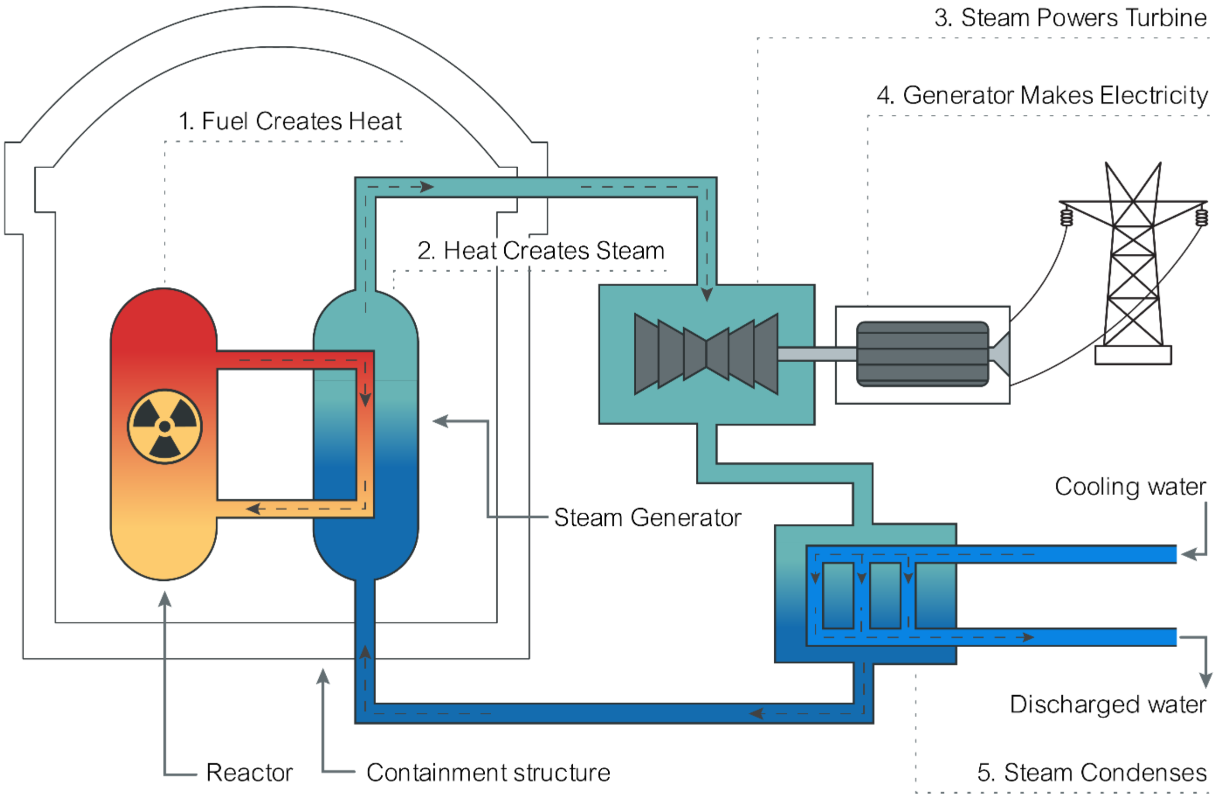

Figure S-4: Thermo-electric generation exemplified by a pressurized water nuclear reactor

Figure S-5 shows the water requirements for candidate technologies for hydrogen production. Between the zero- or low-GHG emissions methods of hydrogen production, hydrogen made from nuclear electricity has over three times the water requirements of the next highest water-intensive method. All the other methods have comparable water consumption needs, except for grey hydrogen, the currently predominant method, which requires about half as much water as green hydrogen.

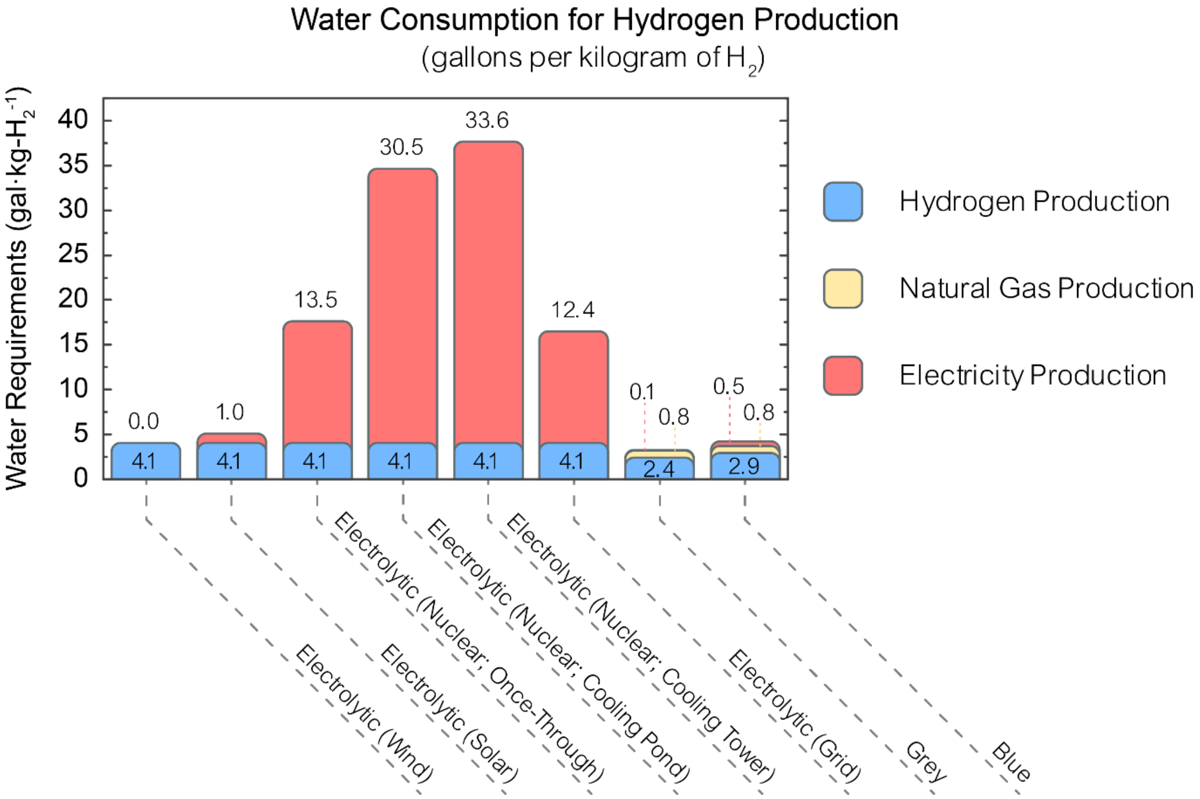

Figure S-5: Water requirements for various methods of hydrogen production, including upstream natural gas for grey and blue hydrogen.

Current total water requirements for hydrogen production are relatively low because the amount produced is almost all as a chemical commodity, and virtually all of it is made as grey hydrogen. This fact is illustrated in Figure S-6, which also projects future water use scenarios if hydrogen production were scaled up according to the "optimistic" case in DOE's hydrogen strategy, which envisions a quintupling of hydrogen production to 50 million metric tons by 2050. Since all of it would be "clean hydrogen", water demands would increase about seven to ten times for a five-fold increase in hydrogen production. The "blue, green, pink" case in Figure S-6 assumes 10% pink hydrogen production, with the rest being green and blue. The specific mix of green and blue hydrogen would not impact water use significantly.

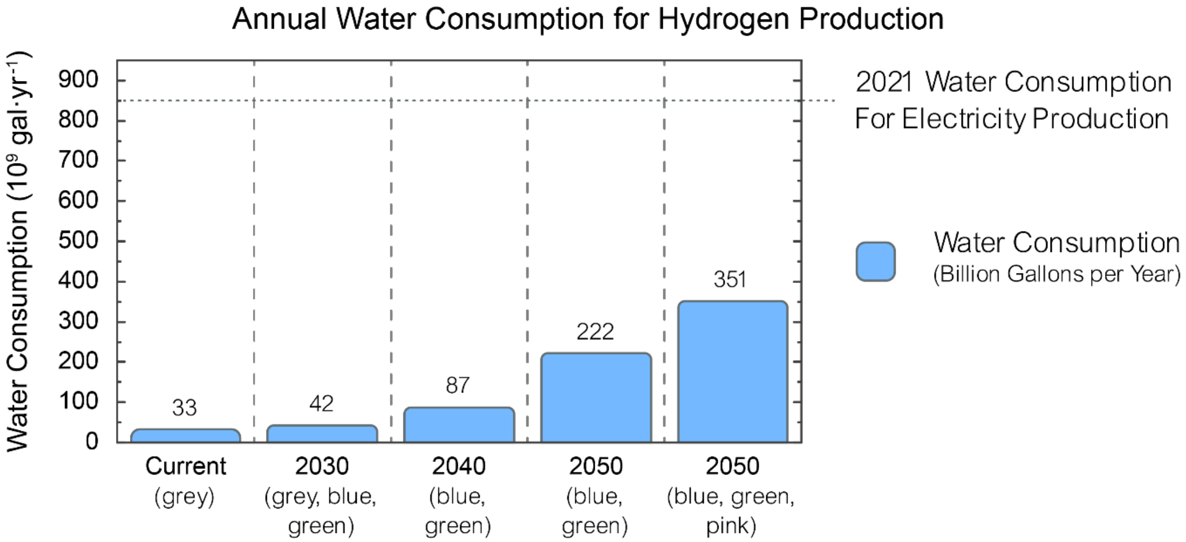

Figure S-6: Water requirements evolution up to 2050 for the DOE draft hydrogen strategy, "optimistic scenario.

The dotted line in Figure S-6 shows present-day water consumption (i.e. water that is evaporated and lost to use) for electricity generation in the United States – water requirements that are second only to agricultural use. A large amount of this water will become available as fossil-fuel-based electricity generation declines and solar and wind generation increase, because solar and wind electricity need almost no water. Fifty million tons of hydrogen production would take up much of this freed water, raising important issues for policy and equity, especially in water-stressed regions. Finally, the large water requirements for hydrogen production could limit production sites to areas where current water supply is relatively plentiful and less threatened by climate extremes.

iii. Geologic and orange hydrogen

There has recently been considerable interest and some investment, including by the U.S. government, in exploring the potential for economically exploitable amounts of naturally occurring hydrogen, sometimes called "white" hydrogen and called "geologic" hydrogen in this report. If such resources exist they could transform the economic landscape of hydrogen. At the same time there are a number of cautions and caveats that may, if adverse, defeat climate goals:

- Geologic hydrogen can contain a variety of impurities from relatively benign gases like nitrogen (N_2) to potent greenhouse gases like methane (CH_4);
- Once drilled, hydrogen may leak from the geologic hydrogen reservoir, in a manner similar to methane with attendant warming and safety implications;
- If the geologic hydrogen is tight formations similar to shale natural gas, then fracking may be necessary to liberate economic amounts of hydrogen;
- Large geologic hydrogen reservoirs, should they exist, may be remote from the places where hydrogen would be used, with leaks attendant upon transport of compressed hydrogen by pipeline or cryogenic hydrogen by ship or rail;
- Geologic hydrogen that are abandoned because they are no longer economical may nonetheless continue to leak, with consequent warming impact.

"Orange" hydrogen while often discussed in the same vein as geologic hydrogen is not natural; it is produced from water injected into geologic formations with suitable chemistry to convert it to hydrogen. Generally, fracking of the formations would be required with unknown consequences for leaks and safety. Water requirements would be large.

Hydrogen production

Findings:

1. Blue hydrogen cannot meet the DOE's draft "clean hydrogen" guidance unless methane leaks are reduced from the present 2.7% to well under 1%.
2. Green and pink hydrogen have zero GHG emissions if dedicated new electricity generation is used. There will be some warming impact of hydrogen leaks, however.
3. System-wide GHG emission increase when diverting *existing* nuclear or renewable sources to make hydrogen, except in the case of use of renewable electricity that would otherwise be curtailed.
4. Hydrogen is a water-intensive commodity. This can place significant constraints in hydrogen production locations, especially in the context of climate change.
5. While geologic hydrogen may hold significant potential if large reservoirs exist, there is a large knowledge gap in regard to its climate implications.
6. Orange hydrogen is not natural; it is made from injected water and carries significant risks including those associated with fracking.

Recommendations:

1. Green hydrogen should be made only from dedicated *new* renewable sources or renewable energy that would otherwise be curtailed. This could apply to pink hydrogen from new nuclear plants. However, these plants are generally associated with significant environmental justice issues. When new nuclear plants might come on-line for this or any other purpose is also an important question.
2. Hydrogen leaks should be included in the CO_2-eq assessment of production methods.
3. Blue hydrogen should not be considered until natural gas *system-wide* reductions of leaks from the present 2.7% to much less than 1% are made.
4. It is essential to consider water supply and water justice issues in siting hydrogen production plants.
5. It is essential to fill climate and other significant knowledge gaps regarding geologic hydrogen before assuming it could play a significant role in the energy transition.
6. The large environmental justice, water use, and fracking implications of orange hydrogen should be assessed before significant investments are made in it.

c. Storage and transportation

Hydrogen must be stored unless it is produced on the site where it is used and at the same rate that it is used. There are three basic methods of hydrogen storage, each with its own characteristics that makes it suitable for specific applications and unsuitable for others:

1. Compressed hydrogen storage in cylinders, at pressures of 200 to 700 bar.[8] This method is suitable for short-term storage, such as that needed for truck refueling stations; this approach is also used for truck transport of hydrogen and for on-board storage in fuel cell vehicles.
2. Cryogenic hydrogen storage, whereby hydrogen cooled to a very low temperature (-253 °C, which is -423 °F) and liquefied. This reduces the volume needed to store hydrogen by well over 800 times, though it is not much less than the volume needed at 700 bar. Cryogenic hydrogen is dense enough to be used as a fuel in aircraft and ships, though neither application is commercialized yet.
3. Underground geological storage. These options are of various types, with the most secure being storage in salt caverns. This form of storage is suitable for large-scale, long-duration, seasonal, storage. While salt caverns are present in many states, they are not available everywhere hydrogen might be used on a large scale, such as at a steel plant or peaking electric power plant.

All forms of storage are vulnerable to hydrogen leaks, with attendant safety and climate issues. But to the extent that hydrogen replaces natural gas or oil, there would be a corresponding reduction of fossil fuel leaks and spills. This does not change the reality of new risks for communities that did not have them until hydrogen was stored or transported through their lands.

Liquid hydrogen has some special and specific risks. Even though liquefied hydrogen containers are well-insulated, they do absorb heat, causing hydrogen to boil. This boiling raises the pressure in the storage tank. To keep this pressure increase from exploding the storage tank, hydrogen is periodically vented through a relief valve. The hydrogen that boils off can be captured; losses can be substantial if it is not: 0.1% to 3% every three days. Using liquefied hydrogen is therefore also more hazardous than using compressed hydrogen. In addition, it can form a flammable ground-level blanket if spilled. It must also be vented away from ignition sources, and safety vents can be clogged by ice formed by the low storage temperatures. Furthermore, hydrogen can be contaminated by air that condenses on to the equipment, forming a highly flammable gas mixture.

d. Uses of hydrogen

Making hydrogen from other energy sources is not 100% efficient. For instance, electrolysis is 60% to 70% efficient. There are also losses when hydrogen is used as an energy source, for instance in a fuel cell truck. The overall efficiency between producing, storing and using hydrogen compounds is expressed as a “roundtrip efficiency”. We will illustrate this concept here for green hydrogen, which would by far be the preferred hydrogen source for applications where it has a climate benefit. In this context, the roundtrip efficiency quantifies how much energy is conserved between using electricity to make green hydrogen, and converting said hydrogen back into energy for its intended the end use. The roundtrip efficiency is 30% to 60%, depending on hydrogen purity requirements and its end uses.

In general, it is much more efficient to use batteries to store energy when the storage time is relatively short, as for example for peaking power production and use in vehicles. The round-trip efficiency varies

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[8] 1 bar pressure is approximately equal to one atmosphere – 14.7 pounds per square inch (psi).

with the age of the battery but is generally much higher for the most common battery: a lithium-ion battery that is several years old would have a round-trip efficiency of about 80%. A relatively new battery would be several percent more efficient. Thus, a given amount of renewable energy can replace almost double the amount fossil fuels when lithium-ion batteries are the storage medium compared to hydrogen. The low-round trip efficiency also means higher fuel costs per mile for fuel cell vehicles, or per kilowatt-hour for peaking electricity generation with fuel cells (or turbines).

Generally, given present and near-term foreseeable technologies, the use of batteries is preferable for light-duty vehicles. The same holds true for heavier vehicles with short ranges, like transit buses and delivery vehicles, and for peaking power production. This conclusion applies so long as there are not large amounts of renewable energy that would be curtailed if it were not stored for a long duration. If electricity would be curtailed, hydrogen is one useful option for long-term storage. But so long as renewable energy plus battery storage can serve existing loads and displace fossil fuels, the use of hydrogen for energy storage should be avoided unless, there are compelling reasons to do otherwise. Refueling time for Class 8 long-distance trucks used for multiple shifts per day could be one such application.

To illustrate this issue further for the case of road transportation, we made a simple comparison for a fixed amount of renewable energy:

- Fuel cell bus plus natural gas heating option: use the renewable energy to make hydrogen to power a fuel cell bus, while continuing the use of natural gas for heating homes.
- Battery bus plus electric heating option: use a battery bus charged using grid-supplied electricity, with typical present-day emissions. Use the renewable energy that is freed up by the high efficiency of battery buses (as compared to less efficient fuel cell buses) to replace natural gas heating with efficient heat pumps.

The result of this example is shown in Figure S-7. The fuel cell plus natural gas heating bus option has about six times the GHG emissions of the battery bus plus electric heating option, mainly because the latter enables the decarbonization of residential heating and because battery vehicles have higher roundtrip efficiency. Both options in Figure S-7 also differ in air quality benefits: each would eliminate air pollution from diesel buses, but the ‘battery bus plus electric heating’ option would also cut back on indoor air pollution from natural gas appliances.

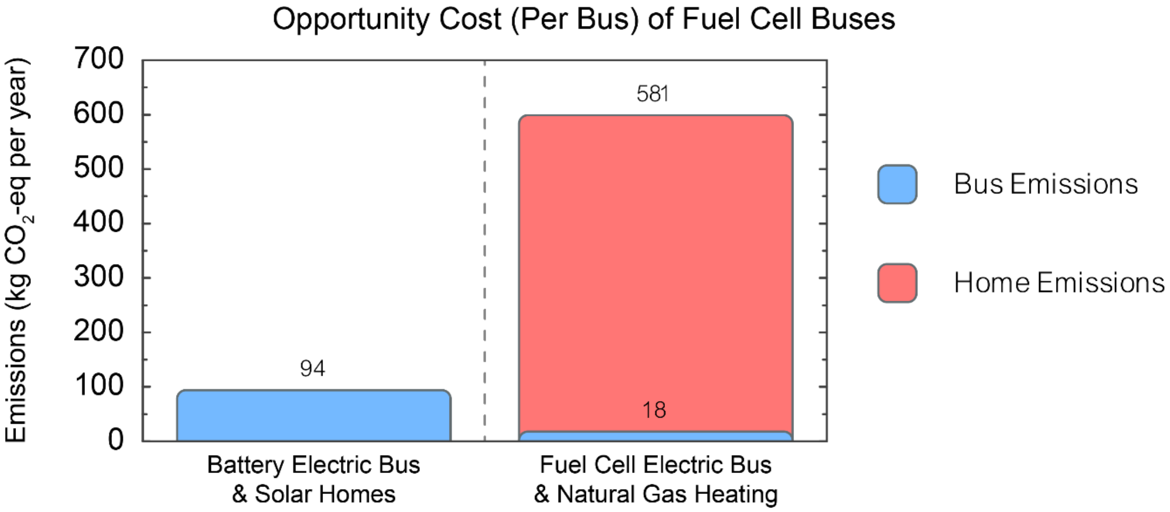

Figure S-7: Comparison of options for powering buses and heating.

Hydrogen could also be used for other applications that cannot directly be electrified, or where electrification is not more efficient than using hydrogen. Steel production is a prime example. Here, using hydrogen instead of coke to reduce iron ore is increasingly well-developed, and promising pilot plants are being built. In contrast, reducing iron ore directly with electricity is still in the early stages of development. For steelmaking, hydrogen is therefore an attractive option. In fact, on an energy basis, hydrogen-based reduction of iron ore requires only 40% as much energy as coke-based reduction in a blast furnace. This makes grey, blue, and green hydrogen all energy-efficient and climate-positive ways to reduce iron ore. (Recycling steel is even more efficient, if sufficient scrap steel is economically available.) In this specific scenario, using grey hydrogen, if already available, for decarbonizing of iron ore reduction could be considered while green hydrogen production is being scaled up, provided that a transition to green hydrogen is made when its cost is low enough. Among the options considered in this report, steelmaking was the only major fossil fuel use where even grey hydrogen would reduce overall greenhouse gas emissions, provided that it does not become a long-term option that would involve continued use of natural gas in the energy system. In the United States, increasing steel recycling could be an even more climate-friendly option.

Other potential uses of hydrogen are long-distance trucks operating in cold climates for multiple shifts, as well as making fuel for long-distance aircraft and ocean-going container cargo ships. At current technology levels, these applications cannot use batteries. However, the climate benefits need to be carefully assessed. For instance, in the case of ammonia as a fuel for container cargo ships, nitrous oxide impacts, if not minimized, may negate the climate benefits even though fuel oil is displaced.

There are also uses that are clearly a poor choice for climate. That is, some uses would worsen climate change or have minimal to no climate benefit, despite the cost, water use, and pollution involved in making and using hydrogen. The most important example in this regard is mixing hydrogen with natural gas in existing natural gas infrastructure. This application is gaining traction around the globe: blending hydrogen volumes of 5% to 50% have been proposed with 20% being a more common proposed upper limit.

In order to adequately estimate the climate benefits of hydrogen blending, one should account for hydrogen being far less energy-dense per unit volume than natural gas. Thus, at 20% hydrogen by volume, it would supply only about 6% of the energy in the gas mixture. This means a higher rate of gas flow for a given end use, which requires higher pressure. These increased pressures also increase the risk of leakage, especially because hydrogen leaks about 4 times more than natural gas at a given pressure. Taking into account these considerations, Figure S-8 shows GHG emissions for mixtures of 5% and 20% hydrogen and compares them to the present-day case of natural gas only. In reality, the impact would be worse than shown because hydrogen leaks associated with its production and at the point of use have not been included. Only pipeline leaks have been taken into account.

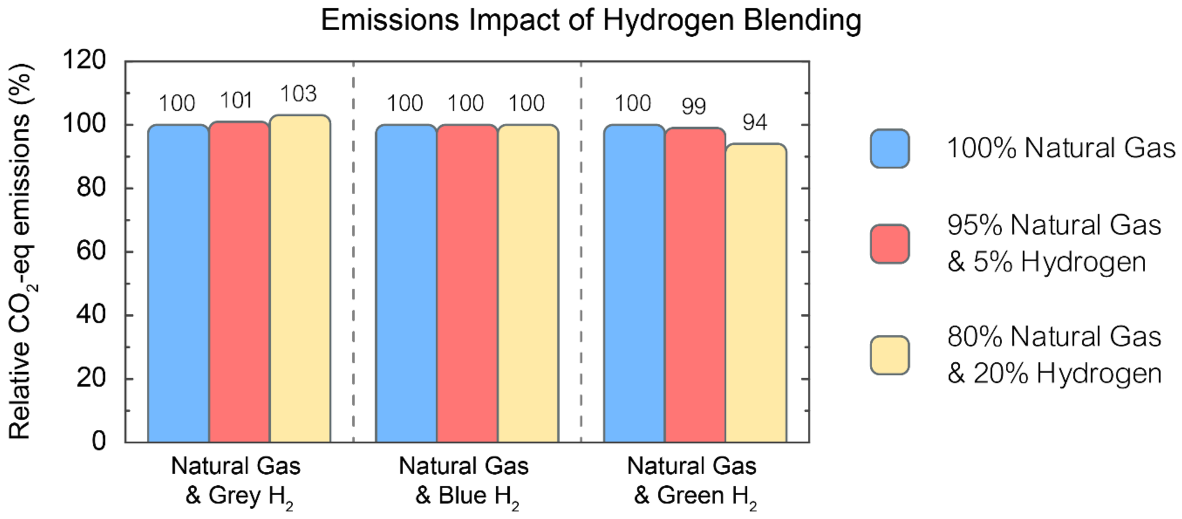

Figure S-8: Greenhouse gas emissions of natural gas alone natural gas with 5% hydrogen and natural gas with 20% hydrogen by volume for grey, blue, and green hydrogen.

As Figure S-8 demonstrates, mixing grey hydrogen with natural gas actually worsens climate change relative to using natural gas alone, while blue hydrogen provides no climate benefit. Only green hydrogen provides a climate benefit, but it is much smaller than the volume fraction of hydrogen added. The marginal benefit in the case of green hydrogen is even more apparent when considering the opportunity cost. Instead of making green hydrogen, the same amount of renewable electricity could be used to directly decarbonize natural gas heating. *The direct use of renewable electricity would displace five times more natural gas than would hydrogen blending.*

Mixing hydrogen and natural gas has three other major disadvantages. First, it does nothing to reduce indoor air pollution from burning natural gas. Instead, it may aggravate it. Second, hydrogen would leak at a faster rate than natural gas. Third, hydrogen can penetrate and embrittle certain types of steel and degrade medium-density polyethylene (MDPE) gas pipes. This raises safety issues as well as climate issues since leaks of natural gas could also increase as a result.

Finally, we estimated the total potential for hydrogen use by about the year 2050 and compared it to the estimate in the DOE hydrogen strategy. The DOE estimates a range of 30 million to 50 million metric tons for hydrogen requirements in the years 2050. Since we have excluded some uses, like mixing hydrogen in natural gas pipelines, our estimates are in the range of 23 million to 39 million metric tons; the higher figure reflects a large use of hydrogen for making liquid fuels like ammonia for ships and hydrocarbon fuels for aircraft. The estimates we have made are not recommendations. Rather, they reflect business-as-usual calculations that omit the uses – such as use in buildings and mixing hydrogen with natural gas – that are clearly not indicated. Assessment of alternatives, such as greater steel recycling or electricity for partly replacing fuel oil in ships as well as opportunity costs should be done before significant commitments for using hydrogen are made.

Producing all or most of this hydrogen would ideally be done by using renewable electricity that would otherwise be curtailed to make green hydrogen. As the fraction of solar and wind electricity in the electricity grid increases, a significant amount of renewable electricity that would be otherwise be curtailed will become available for some form of long-duration storage, for which hydrogen is one good candidate, though not the only one. Were all surplus renewable energy used to make hydrogen, we estimate it could yield about 30 million metric tons of green hydrogen around the year 2050. In practice, this surplus would be used for a mix of storage technologies such as long-duration battery storage, seasonal thermal storage, and compressed air storage.

e. Environmental justice issues

There are environmental justice issues at every step when hydrogen is used as an energy source. There are also environmental benefits, since hydrogen would displace fossil fuels. For instance, when green hydrogen displaces natural gas use, fracking-related water pollution, air pollution, and seismic risks are reduced. Evaluating these benefits and harms warrants a local accounting of environmental impacts and justice-related implications, as well as a global accounting to assess the overall environmental positive and negative impacts.

This report is focused on hydrogen and climate. Chapter VII flags environmental justice issues for consideration and potential future detailed analysis.

i. Safety

Hydrogen is combustible and explosive when mixed with air over a wide range of concentrations: 4% to 76%. As a result, safety is an issue at production locations, during transport, and for storage including large scale underground storage of hydrogen. We should note that safety issues are a routine part of the existing hydrogen industry. However, there is much less experience with the decentralized production and use of hydrogen.

Electrolysis is currently a very minor production method. The fact that electrolysis splits water into hydrogen and oxygen raises safety issues, because a mixture of these gases that can result in fires and explosions. Importantly, hydrogen flames have a pale blue color that is almost invisible in daylight. Well-designed electrolyzers that operate according to their specifications produce separate streams of hydrogen and oxygen, minimizing the risk of explosion and fire. However, the largest and most important opportunity for climate-beneficial low-cost green hydrogen is to make it intermittently with renewable electricity that would otherwise be curtailed. Not all electrolyzers are suitable for such operation, and using improper electrolyzer types for this mode of operation poses the risk of producing explosive hydrogen-oxygen mixtures (see Chapter IV).

ii. Water requirements and water pollution

Producing hydrogen comes with various concerns surrounding the use and pollution of water.

- Purifying water for electrolysis yields a stream of waste water. This water stream has a higher concentration of dissolved solids than the source water. Such rejected water can often be returned to the source, but may need to be handled as environmentally hazardous brine in niche applications.
- Siting electrolytic production could be constrained by the locally available water supply: if inappropriately sited, hydrogen production could create significant equity issues, especially in the West and Southwest, where water supply is already a major concern and equity issue.
- Water consumption is much larger for pink hydrogen when nuclear plant is cooled with freshwater (as distinct from seawater, which has its own issues).
- A great deal of water will be liberated as solar and wind energy displace thermo-electric power generation using fossil fuels. Significant issues of water rights and claims could arise. Use of water for hydrogen production could imply large opportunity costs in terms of water not available for other uses such as farming and domestic water supply.

iii. Blue hydrogen

Grey hydrogen is produced using natural gas and water as the main raw material; it is the predominant production method today. Blue hydrogen uses the same process but adds carbon capture and sequestration. This raises a host of environmental justice issues, including

- Continued production and transportation of natural gas, including that produced by fracking;
- Pollution issues associated with CCS;
- The continued presence of polluting facilities in EJ communities with new risks added to existing ones;
- Safety issues associated with CO_2 transport in pipelines through communities;
- Safety and environmental issues associated with injection of CO_2 in different geologic formations at the time of sequestration and over the long-term.

iv. Scarce materials

Electrolysis involves the use of scarce materials like iridium and platinum as catalysts. The places where these materials are mined and refined would experience adverse impacts. Many are in the Global South, as is the case with iridium and platinum production in South Africa. There are also disproportionate impacts of mining on Indigenous lands in the Global North. Net mining impacts should also be considered, since fossil fuel production and use also involves material production impacts that would be avoided when green hydrogen displaces them. Therefore, the following issues could be examined:

- The site-specific issues involving the main materials that must be mined and processed – with a focus on the Global South and Indigenous lands, including the illustration of differential impacts;
- Impacts of recovering and recycling hydrogen-related materials – as well as avoided mining and processing impacts when materials are recycled;
- Global net impacts, including avoided fossil fuel-related mining and processed impacts.

v. Pink hydrogen

Pink hydrogen is hydrogen produced by electrolysis of water using nuclear electricity. There are a host of issues associated with the use of nuclear energy that arise mainly from nuclear fuel mining and production, as well as the intensely radioactive spent fuel that contains plutonium. The longevity of these wastes is remarkable. For example, uranium mill tailings contain thorium-230, which has a half-life of about 75,000 years; it decays into radium-226 and then radon gas. Another waste product, plutonium-239, present in spent fuel, has a half-life of over 24,000 years.

vi. Other hydrogen production methods

Landfill gas and biomass have been proposed as raw materials for hydrogen production. Given the location of landfills, this has evident environmental justice implications.

Biomass has implications for land use, climate, soil carbon, as well as the environmental justice issues associated with siting.

vii. Burning hydrogen

Hydrogen creates air pollution, notably nitrogen oxides, when burned. Air pollution and associated environmental justice impacts can be explored in the various contexts in which hydrogen burning has been proposed, including for generating electricity using gas turbines, and using it in buildings for heating. The latter would disproportionately affect renters and, among them, low-income and BIPOC renters who are generally not in a position to electrify their natural gas heating systems.

viii. Synthetic fuel production

Liquid fuels – ammonia as well as hydrocarbon fuels – can be produced using hydrogen as one of the inputs. Other inputs could be captured CO_2, biomass, landfill gas, and biofuels made from crops. The manufacture of synthetic hydrogen carbon fuels would constitute a major new chemical industry, with attendant economic, ecological, and environmental justice implications. It could also constitute a major use of hydrogen, the extent of which would depend on which specific fuels and technologies come to widely used.

For instance, hydrogen may also be used as a feedstock, along with CO_2, to produce synthetic jet fuel; currently various toxic chemicals, including toluene, are added to petroleum-derived jet fuel. Ammonia, made with hydrogen as a feedstock, has also been proposed as a fuel. Ammonia emissions create air pollution, including NO_x and PM2.5 particulate pollution, and may, in some circumstances, result in climate warming impacts greater than burning coal, while exposure to other chemicals involved in such fuels presents various hazards to human health, as well as environmental risks.

ix. Perpetuation of the natural gas industry

A significant role for blue hydrogen brings with it the risk of a long-term role of natural gas in the energy system. This would perpetuate the many environmental justice and ecological impacts of natural gas production and use. Similarly, mixing hydrogen with natural gas for use in building heating and power production would have minimal climate benefits, even with green hydrogen. Thus, this use of hydrogen would mainly serve the purpose of entrenching the natural gas industry in the energy system. A detailed exploration of this use in the residential sector impact could be done from the economic, environmental justice, and climate aspects.

The entrenchment of the oil and gas industry is also a risk with geologic and orange hydrogen should they be produced in quantity.

x. Steel

Using hydrogen instead of coke for steel production from iron ore significantly reduces greenhouse gas emissions, even with grey hydrogen. Emissions are reduced more with blue hydrogen and eliminates them when using green hydrogen in a decarbonized grid. Since green hydrogen is scarce and expensive and there are many competing uses for renewable energy and even green hydrogen, the question arises whether grey hydrogen, if already available, could be used for an early transition in the steel industry to get GHG emission reductions without CCS (which has time and environmental justice issues as well). One could then transition to green hydrogen from grey as that becomes available in larger quantities, possibly in a decade or more. The use of grey hydrogen would imply increasing the use of natural gas, a fossil fuel that needs to be phased out. Such an increase is generally undesirable. At the same time, not switching to hydrogen if it is available implies the continued use of coke. This use is paired with larger GHG emissions and the release of a variety of other toxic pollutants, as discussed in Chapter VI Section b.iii. This is a complex economic, environmental justice, and climate issue. A more detailed examination is needed to clarify its implications for phasing out natural gas and from an environmental justice standpoint. We note here that this is a more pressing issue globally where most steel is still made with iron ore as the raw material, while the vast majority of steel in the United States is made by recycling scrap steel for which hydrogen is not needed. Moreover, the issue would be moot in the United States if increasing recycling can meet the need.

xi. Opportunity costs of using hydrogen

There are a number of areas where the use of green hydrogen would reduce CO_2 emissions, but would represent a waste of renewable energy resources. Other things being equal, even approximately, the use of renewable electricity directly or coupled with storage is generally far more beneficial for decarbonization and also more economical. Some examples of the significant lost opportunities for climate and economic justice are in the report. These could be explored in more detail and other examples could be developed.

II. Hydrogen Basics

a. What is hydrogen?

Hydrogen is the lightest and simplest element, consisting of one proton and one electron (Figure II-1). It is also the most abundant element in the universe, is a small fraction of the Earth's crust and is present in soil, rocks, fossil fuels, and all living beings in the form of water (H_2O) or organic molecules. It is also a major commercial commodity in the form of H_2, with about 10 million metric tons industrially produced annually in the United States, with an additional 3 to 4 million metric tons produced internally in the petroleum refining and chemical industries.[9] Globally, hydrogen production is about 75 million metric tons with an additional 17 million metric tons in the petroleum refining and chemical industries.[10]

As discussed in Chapter IV, there may even be reservoirs of natural hydrogen underground that could be tapped where it may be continually made. The amounts of such subterranean elemental hydrogen are very uncertain, and therefore, so is its potential as a fuel.

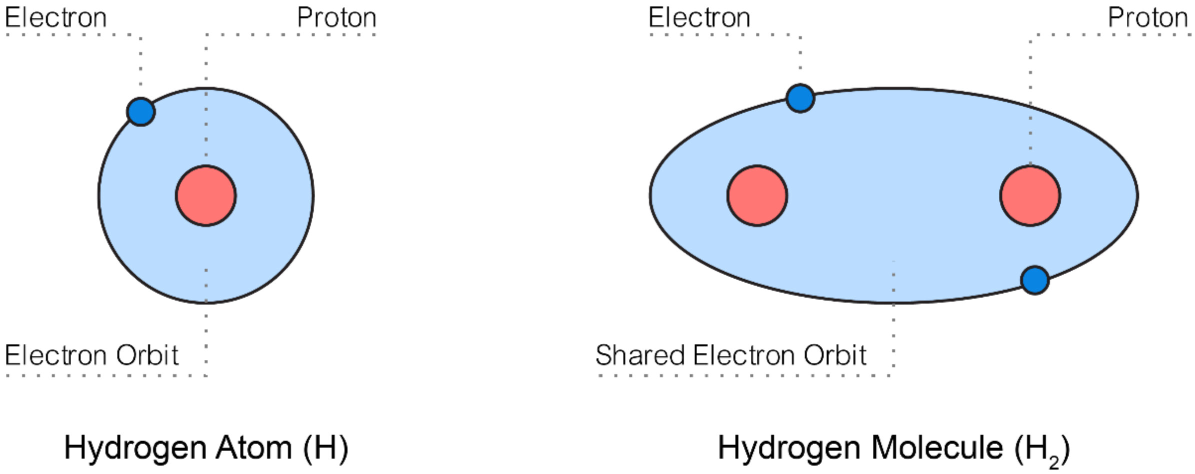

Figure II-1: Schematic representation of a hydrogen atom and molecule.

Hydrogen is present as a trace gas in the atmosphere at about 0.5 parts per million.[11] It is usually in the form of a diatomic gas, H_2, each hydrogen atom sharing its electron with the other to form a molecule (Figure II-1). H_2 is present in very low concentrations because it is a reactive gas: it reacts with oxygen in the atmosphere, thereupon becoming water vapor. Atmospheric hydrogen has both natural and anthropogenic sources (see Chapter III).

The potential for hydrogen to be used as a fuel has been discussed for decades. Hydrogen can be used as an energy source by oxidizing it, turning it into water:

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[9] Brown 2016, Figure 1

[10] McKinsey 2022

[11] This is the volume fraction, which is the same as the molar fraction – that is, there are 0.5 moles of hydrogen for every million moles of air overall. In terms of mass, the atmosphere has a mass of about 5.1 million trillion kilograms; of that hydrogen is about 0.2 trillion kilograms (rounded).

$2H_2 + O_2 \rightarrow 2\ H_2O$

This reaction produces water as the only product (along with electrons) when the conversion takes place in devices called “fuel cells”. However, hydrogen also can be combusted to achieve the same reaction, which can create byproducts: hydrogen flames are very hot, and these high temperatures cause nitrogen in air to react with oxygen, thus producing harmful nitrogen oxides. If the reaction is carried out in pure O_2, nitrogen oxides would not be formed.

There are also some serious downsides to using hydrogen, which is why hydrogen is not yet a common energy carrier. First, while its mass energy density is high, its volumetric energy density is low: less than 30% of natural gas and hundreds of times less than liquid petroleum-derived fuels. To be used in motor vehicles, hydrogen needs to be compressed to pressures hundreds of times higher than atmospheric pressures. In the alternative, it needs to be cooled to a very low temperature of 253 degrees below zero Celsius (423 below zero Fahrenheit) and liquified: a costly and energy-intensive process. A third option is to make ammonia (NH_3) from it and use that as a liquid fuel. Ammonia can also be used as an energy carrier for more economical transportation and reconverted to hydrogen at the point of energy use.

Another obstacle is that, unlike fossil fuels, uranium, wind, or solar energy, until very recently, hydrogen was not considered to be available as an abundant naturally occurring resource. But, as discussed in Chapter IV, this has changed significantly: in the United States, both corporations, including oil and gas companies, and the federal government have begun committing significant resources into the exploration of natural, geologically occurring hydrogen.[12] We will use the term ‘geologic hydrogen’ to refer to naturally occurring hydrogen in the subsurface layers (beneath land or beneath the ocean floor). The United States Geological Survey is conducting investigations of the potential of geologic hydrogen as a resource, using, in part, the extensive experience of the oil and gas industry.[13]

So far, all the hydrogen that is used as an industrial commodity is made from some other fuel. This involves both expense and energy losses. Currently, hydrogen is most commonly made from natural gas: in the United States, about 95% of commodity hydrogen is produced from natural gas (Chapter IV), and worldwide wide the fraction is about three-fourths. Almost all the rest is made by coal gasification with steam. It has generally been simpler and cheaper just to use the fossil fuel directly for energy purposes. Hence, to date, commodity hydrogen is rarely used as an energy source; rather, it used as an industrial feedstock (for making ammonia, for instance) or as a process chemical (mainly in petroleum refining). Globally, hydrogen production results in over 900 million metric tons of CO_2 emissions;[14] this amounts to about 10 metric tons of CO_2 per metric ton of hydrogen (rounded); this does not include the CO_2-equivalent warming impact of methane leaks associated with natural gas and coal production, which could add roughly 50% to the estimated emissions rate (using a 20-year warming potential for natural gas: see Chapter III).[15]

Despite this industry-focused hydrogen use, much more serious attention has been paid to hydrogen as an energy source in recent years in the context of the climate crisis, since it has no carbon emissions at the point of use. Thus, if hydrogen can be made from an energy source that itself has no carbon emissions, it could be useful in the context of creating an emissions-free energy system. So far, it has

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[12] ARPA-E 2023

[13] USGS 2023

[14] IEA 2022, p. 71

[15] Rhodium Group 2015. Assuming a global natural gas leak rate of 3%. Globally, about three-fourths of the natural gas is produced from natural gas and almost all the rest is with coal (IEA 2022).

generally been cheaper to avoid the expense of making hydrogen and instead use the zero-emissions energy source directly, if possible. However, hydrogen has properties that enable it to replace particular fossil fuel needs that cannot be easily fulfilled by using electricity. Hydrogen can also be used as a feedstock to make other fuels that are more energy dense per unit volume – like ammonia or hydrocarbon fuels for aircraft. These uses are discussed in Chapter VI.

There are a variety of methods to produce hydrogen. The following are among the most prominent:

1. **Steam methane reforming (SMR) of natural gas, called "grey" or "gray" hydrogen**: Natural gas is reacted with steam to produce hydrogen and carbon monoxide; in a second reaction the carbon monoxide reacts with steam to produce CO_2 and hydrogen. The process inherently produces CO_2 and, since it involves the use of natural gas, there is an additional warming impact due to methane leaks; methane is the main constituent of natural gas. Auto-thermal reforming is a variant of the process and also uses natural gas as the feedstock.
2. **Steam methane reforming of natural gas with carbon capture and sequestration (CCS), called "blue" hydrogen**: The hydrogen production process is identical to steam methane reforming, but CCS is added to reduce greenhouse gas emissions. CCS increases the energy used. The overall reduction of emissions per unit of hydrogen production depends on the efficiency of CO_2 capture and how well the CO_2 is sequestered. Regardless of how these two factors shake out, blue hydrogen has a substantial warming impact due to its high energy intensity and methane leaks.
3. **Coal gasification with steam and oxygen, called "black" hydrogen if bituminous coal is used and "brown" hydrogen if lignite is used**: The process is similar to the production of "town gas" (hydrogen plus carbon monoxide) from coal with the added step of reacting the carbon monoxide with steam. It generates more CO_2 per unit of hydrogen than steam methane reforming. It would not be viable as a low carbon energy source without CCS and, as such depends on the viability and efficiency of CCS.
4. **Electrolysis**: Hydrogen can be produced by splitting water molecules into hydrogen and oxygen using electricity (called "electrolysis"). The carbon intensity depends on the source of the electricity:
    1. "Green" hydrogen: electrolysis using solar or wind electricity;
    2. "Pink" hydrogen: electrolysis using nuclear electricity;
    3. "Yellow" hydrogen: electrolysis using electricity from the grid, with the carbon intensity depending on the carbon intensity of the electricity supply (which may be variable);
5. **Methane pyrolysis, called "turquoise" hydrogen**: In this production method, methane at high temperature in the absence of oxygen is converted to elemental carbon (which can be stored) and hydrogen. Since no water is used, twice as much natural gas is required to produce the same amount of hydrogen as the steam methane reforming process, where half the hydrogen comes from water (in the form of steam); the warming impact would be primarily from methane (natural gas) leaks if the carbon is sequestered, as well as any emissions associated with powering methane pyrolysis.
6. **Geologic hydrogen, called "white" hydrogen**: Naturally occurring hydrogen may be mined if found in economically significant quantities; warming impacts would be primarily via hydrogen leaks (see Chapter III).
7. **Stimulated geologic hydrogen, called "orange" hydrogen**: Hydrogen that forms when hydraulically fracturing (fracking) iron-rich rocks. When water is exposed to these rocks, hydrogen could form underground. This hydrogen may then be extracted.

Hydrogen, like all energy sources, has the potential to have adverse impacts that will need to be addressed and minimized, including cost, emission of non-greenhouse gas pollutants, and indirect warming impacts due to hydrogen leaks. Furthermore, increased production of scarce materials, like iridium and platinum, is likely to be involved when producing hydrogen from water. It will also be important to estimate the net change in warming impact when hydrogen replaces fossil fuels. This net change depends on many factors, including the method and efficiency of hydrogen production, the hydrogen leaks through the entire cycle of production, transportation, and use, and the efficiency of hydrogen use relative to that of the displaced fossil fuels.

This report is an exploration of the role that hydrogen could play in a transition to an emissions-free energy system. It aims to address the potential environmental impacts, including environmental justice aspects in the places where hydrogen facilities (production, transportation, storage, use) might be located or in the places that might be impacted by an energy system that has a significant role for hydrogen. Uses and production methods that could be counterproductive from a climate point of view are also discussed. Finally, areas where the assessment is more complex or where short-term uses might be contra-indicated and long-term use indicated are also discussed.

b. Current and future uses of hydrogen

Figure II-2 shows the current uses of hydrogen – almost all of which are in heavy industry. The total amount of hydrogen used in 2015, when very detailed breakdown of uses is available, was about 14 million metric tons.[16] Of this hydrogen, about 4 million metric tons were generated within the petroleum refining and other chemical industries as a byproduct and used within them as a feedstock or fuel. An additional 10 million metric tons were produced as a commodity and sold to industry and for some minor uses, like cooling the electricity generators at centralized power plants.

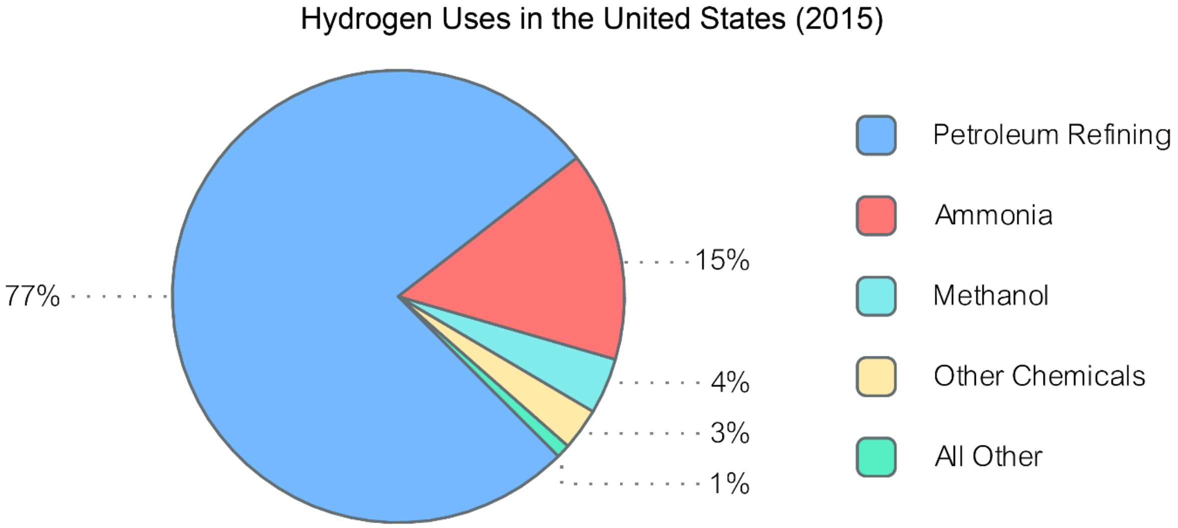

Figure II-2: Hydrogen uses in the United States, 2015, including hydrogen internally produced in the refining and chemical industries. Source: Brown 2016.

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[16] IEA 2022, p. 18, indicates that hydrogen use in the United States remained at about the 2015 level until 2021.

Figure II-2 shows all the hydrogen that was used, including that produced in the course of petroleum refining and in the chemical industry. Of the 10 million metric tons that was produced as a commodity just under 60% was used in petroleum refining, and most of the rest was used for ammonia and methanol production. Hydrogen is also used in the food processing industry to hydrogenate vegetable oils and as a coolant for the electric generators in centralized power stations. It is not consumed in the latter case, but rather recirculated.

As Figure II-2 shows, production and use of hydrogen on an industrial basis is well-established. However, use of hydrogen as an energy source is still in its early stages. Very large increases in the use of hydrogen as an energy source are envisioned, albeit from the small amount so used today. There are a variety of opinions and estimates on how much and how fast hydrogen energy can expand and in what applications it would be useful and desirable from the point of view of mitigating climate impact. Ambitious global hydrogen use projections are for a global increase in the range of 600 to 660 million metric tons, a roughly seven-fold increase by 2050 compared to 2021.[17] The Department of Energy hydrogen strategy has a base case of about 30 million metric tons by 2050 and an optimistic estimate of 50 million metric tons by that date.[18] In addition to ammonia and methanol production, which would continue, the US strategy envisions used in long-distance truck transport, electricity generation, liquid fuel production using hydrogen as a feedstock, steel production, and use in buildings. It is noteworthy that the DOE hydrogen strategy estimates that the petroleum refining sector would no longer be a consumer of hydrogen. Uses are discussed in Chapter VI.

This report addresses many but not all aspects of the issue of where, when, and how much hydrogen might be best deployed for a clean energy transition to have a net reduction in warming impact. We discuss some environmental and environmental justice aspects of producing and deploying hydrogen as an energy source. We also examine where it would be inadvisable for various reasons, ranging from climate protection to environmental justice to speed and economics of the energy transition to not use hydrogen as an energy source. We also discuss areas of uncertainty where the prospects are unclear. A major area of uncertainty is the existence, extent, cost, and geographic distribution of gaseous hydrogen as a natural resource.

Finally, we note that hydrogen needs to be seen and modeled as part of the transformation of the entire energy system, including its decarbonization, achieving collateral environmental benefits, such as reducing air and water pollution, and improving energy affordability and energy system resilience. These considerations will be highlighted where appropriate.

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[17] McKinsey 2022

[18] DOE Strategy 2023

III. Hydrogen and Climate

Note: This chapter addresses only climate change issues and hydrogen. Other issues, such as the non-climate environmental impacts of hydrogen production will be addressed to varying degrees in other parts of the report. These include impacts related to materials needed for electrolysis and fuel cells and impacts of carbon capture and sequestration.

Hydrogen is not in itself a greenhouse gas because, unlike carbon dioxide (CO_2) or methane (CH_4) in the atmosphere, it does not directly trap outgoing infrared radiation and radiate it back to Earth. However, hydrogen is an *indirect* greenhouse gas: it impacts warming mainly by extending the lifetimes and concentrations of greenhouse gases, notably methane. It also increases tropospheric ozone and stratospheric water vapor, both of which have a warming impact. Hydrogen's potential contribution to climate change should therefore be taken into account when assessing its overall impact as a climate solution, especially because hydrogen leaks easily from production, distribution, and usage infrastructure.

Even today, there is already a substantial amount of hydrogen in the atmosphere: part of it is natural and part is the result of human activities. Atmospheric hydrogen concentrations are low, but it is still important to assess hydrogen's current warming impact as a baseline, since it is not fully understood; any emissions due to increases in hydrogen use would add to that baseline impact, while also potentially reducing warming associated with the fossil fuels it is replacing. We first consider the present sources of hydrogen, then warming mechanisms, and finally potential impacts of hydrogen leaks as hydrogen use as an energy source increases.

a. Existing hydrogen sources and sinks

As discussed in Chapter II, at about 0.5 parts per million (ppm), hydrogen is a trace gas in the atmosphere. Despite this small relative amount (methane is about 1.9 ppm and CO_2 is about 420 ppm), the total mass of atmospheric hydrogen is still substantial. The concentration is the result of sources and sinks, both of which are partly natural and partly anthropogenic. These sources and sinks are represented in Figure III-1, which is a schematic of sources, (red arrows), and sinks (green arrows) given in units of million metric tons (Mt).

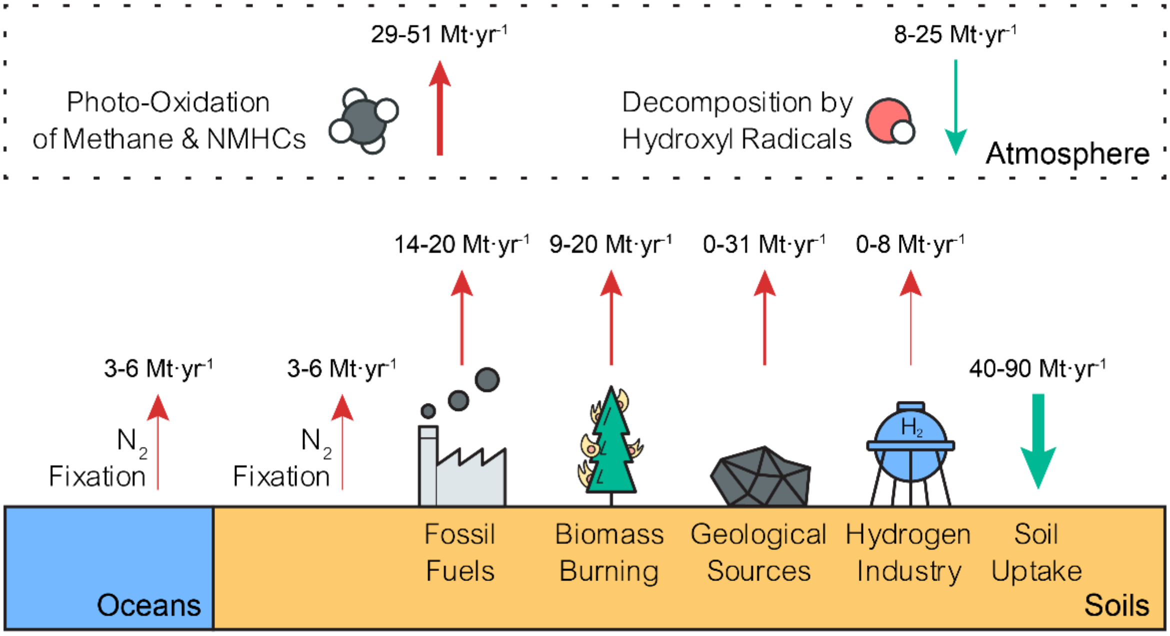

Figure III-1: Sources and sinks of hydrogen, in million metric tons per year. CH_4 is methane; NMHCs are non-methane hydrocarbons. Mt = million metric tons.
Source: Based on Figure 1 in Arrigoni and Bravo-Diaz 2022, and adapted for this report under Creative Commons Copyright.

Although there are significant uncertainties in the size of sources and sinks of hydrogen, Figure III-1 provides a useful visualization of the approximate size of each. In terms of sources, the “fossil fuel” and “hydrogen industry” sources are directly attributable to those industries – and are thus anthropogenic sources. There are also large indirect sources of hydrogen, with the most important resulting from decomposition of methane and non-methane hydrocarbons (“NMHCs”) in the atmosphere, both of which have natural and anthropogenic sources, though natural sources dominate.[19] Currently, most accumulated methane in the atmosphere is due to a mix of agricultural sources and emissions from the fossil fuel industry. As a result, the indirect hydrogen source due to methane (CH_4) is largely anthropogenic. The schematic makes clear a reinforcing effect: more methane in the atmosphere means more hydrogen and more hydrogen means more methane. The additional “geological sources” are seeps from natural sources in soil and rocks. The magnitude estimate of these sources encompasses a large range, including zero at the lower end; this spread represents major uncertainties regarding the underground natural processes that generate hydrogen. If substantial concentrated sources of natural hydrogen exist, they could become a source of supply for the energy transition (see Chapter IV).

Counteracting these hydrogen sources is a set of two sinks: hydrogen decomposition in soils and in the atmosphere. The first consists of bacteria in the soil that use hydrogen an energy source. The concentration of bacteria and their metabolic rates depend on a variety of factors, such as soil moisture and temperature. In turn these factors are affected by climate change, introducing additional uncertainty as to how much hydrogen might accumulate for a given rate of leaks as climate changes. In addition to the soil hydrogen sink, there is a sink that corresponds to the breakdown of hydrogen in the atmosphere.

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[19] Guenther *et al.* 2000

Specifically, hydrogen gas in the atmosphere reacts with the hydroxyl radical ($OH^\bullet$), as indicated in Figure III-1; the hydrogen radical, $H^\bullet$, shown in the figure undergoes further oxidation reactions. This decomposition pathway, which is responsible for hydrogen's indirect warming effect, will be explored in more detail in section "b." of this chapter.

Arrigoni and Bravo-Diaz (2022) estimate that the total hydrogen source term – natural and human – is in the range of 60 to 140 million metric tons, while the total sink is in the range of 50 to 110 million metric tons; each has an uncertainty of more than a factor of two. As a result, there is also considerable uncertainty about the lifetime of hydrogen in the atmosphere, normally considered to be about 2 years. This lifetime factors into the ways in which hydrogen affects global warming. In spite of these uncertainties, recent research supported by ice-core records indicates that, in the past 100 years, the cumulative magnitude of hydrogen sources has been larger than hydrogen sinks. In other words, more hydrogen has been added to the atmosphere than has been removed: atmospheric hydrogen concentrations have increased by 70% over the twentieth century.[20] This excess hydrogen is likely caused by an increase of direct hydrogen emissions by human activities, as well as an increase in methane emissions that create hydrogen when the methane breaks down in the atmosphere.

b. Warming mechanisms

Both past and possible future hydrogen accumulation in the atmosphere can pose serious climate risks, because of how hydrogen breaks down once emitted: as mentioned earlier, hydrogen is an *indirect* greenhouse gas, which means that its decomposition increases the atmospheric concentration of greenhouse gases. This indirect climate effect of hydrogen is explored in this current section.

When in the atmosphere, hydrogen reacts with hydroxyl radicals ($OH^\bullet$), which are water molecules stripped of one of their hydrogen atoms. Hydroxyl radicals are a powerful oxidizer and exist in the atmosphere only in trace concentrations – a fraction of a part per trillion. They have an atmospheric lifetime of less than one second.[21] Because of their reactivity, OH radicals are the main chemical cleanup mechanism of the atmosphere, removing a large variety of polluting molecules by chemical reactions, including methane, unburned hydrocarbons, and hydrogen.

The details of these chemical reactions are quite complex, but the bottom line is relatively simple: if more chemical pollutants are present in the atmosphere, it will take more hydroxyl radicals to consume them. Thus, adding pollutants to the atmosphere will leave fewer hydroxyl radicals to remove other pollutants that were already there. For instance, methane emissions have a self-reinforcing ("positive feedback") effect: increasing methane emissions cause more hydroxyl radicals to react with methane. Thus, the hydroxyl radical concentration decreases, which in turn slows down methane breakdown and increases the total accumulation and warming impact of methane for a given level of emissions. The accumulation rate – and hence warming impact – represents the balance between emission rates and removal rates. Consequently, reducing the methane removal rate by hydroxyl radicals has the same impact as increasing methane emissions. In other words, by reducing the removal rate of methane, hydrogen effectively increases its average "lifetime" in the atmosphere, which is defined as the time it takes to remove 63% of a pulse emission a gas from the atmosphere.

Thus, short-lived greenhouse gases like methane and hydrofluorocarbon refrigerants (HFCs) exhibit a positive feedback effect by increasing their own lifetimes and the lifetimes of other pollutants affected

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[20] Patterson et al. 2021

[21] Isaksen and Dalsøren 2011

by the hydroxyl radical. Hydrogen, though not a greenhouse gas itself, acts similarly – largely by reacting with hydroxyl radicals and reducing their availability for removing greenhouse gases like methane.

Increasing the lifetime of methane represents about half the warming impact of hydrogen, which also creates warming impacts by producing two other molecules when it reacts with hydroxyl radicals:[22]

- A hydrogen radical ($H^\bullet$) is created when hydrogen gas reacts with the hydroxyl radical (see Figure III-1). The hydrogen radical then undergoes a series of chemical reactions in the troposphere (the atmosphere from the surface of the Earth to about 10 to 15 kilometers altitude) to create tropospheric ozone (O_3), which is a greenhouse gas. In the troposphere, ozone is also a pollutant which damages the lungs. The production of tropospheric ozone represents about 20% of the warming impact of hydrogen.
- Some of the hydrogen migrates across the tropopause (the boundary between the troposphere and stratosphere), into the lower stratosphere.[23] Upon oxidation there, it becomes water vapor, which is a greenhouse gas: it represents about one-third of the warming impact of hydrogen.[24]

There are two scientifically straightforward ways to assess the warming impact of hydrogen. The most comprehensive and accurate method is to estimate its impact on radiative forcing, which represents the rate at which added energy is directed back to the Earth's surface: it is a direct measure of warming, expressed in watts per square meter per unit concentration of hydrogen. Radiative forcing of all gases can be added up to get total radiative forcing. If calculated as a function of time, it automatically takes account of the varying emissions and different lifetimes of the gases that affect warming. The other method is to use a global warming potential, which is a time-integrated metric that compares every gas to CO_2 as the reference gas, whose impact is set equal to 1. As a result, the GWP depends on the integration time chosen. It is discussed in Section III-e below in the context of adding impacts of warming gases.

Warming impact is measured in how much heat is radiated back per unit area of the Earth (watts per square meter); this measure is called "radiative forcing." Bertagni et al. (2022) cite the warming impact of hydrogen as being in the range of 0.13 to 0.18 milliwatts per square meter per part per billion and report a hydrogen concentration of 530 parts per billion.[25] The warming impact baseline of hydrogen on this basis amounts to 0.08 W/m^2. Roughly a third of this, or almost 0.03 W/m^2 (rounded), is attributable to anthropogenic activities. Comparing this to the overall anthropogenic "radiative forcing" (as the warming impact is called) of 2.72 W/m^2 (as estimated in the Sixth Assessment report of the IPCC)[26] leads to the conclusion that on the order of 1% of industrial era warming is due to anthropogenic hydrogen warming. Although the current warming impact of hydrogen is relatively minor, it indicates that it is important to consider hydrogen leaks in a hydrogen economy because a high level of leaks could negate its desired climate benefits. In fact, high levels of leaks might even result in adverse climate impacts.

c. Present and possible future hydrogen leak rates

Hydrogen leaks are part of an overall scheme of assessing the net climate impact of using hydrogen as an energy source. Hydrogen impacts emissions in three ways:

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[22] Ocko and Hamburg 2022

[23] NASA 2021. Water vapor is a few parts per million of stratospheric air.

[24] Warwick et al. 2022, pdf p. 10

[25] Bertagni et al. 2022

[26] IPCC 2021, p. 91

1. Emissions resulting from hydrogen production (covered in Chapter IV);
2. GHG emissions avoided from the use of hydrogen as an energy course;
3. Hydrogen leakage and the related issue of prolonging the lifetime of atmospheric methane, covered in this chapter.

The previous discussion suggests that anthropogenic sources of hydrogen (direct and indirect) already exert a warming impact of roughly 1% of total global warming. Increases in net hydrogen emissions would add to this warming impact, all other things being equal. However, they are generally not equal: using hydrogen could decrease some greenhouse gas emissions, while increasing others.

Methane has far greater warming impact than hydrogen: the impact of a kilogram of methane is about 2.5 times more than a kilogram of hydrogen when averaged over 20 years, and about 7.5 more when averaged over 100 years.[27] Both have a warming impact far greater than CO_2 (which is the reference gas with a global warming potential set equal to 1). The net warming impact of using and producing hydrogen is highly dependent on the rates of hydrogen methane leaks over the entire production, transportation, storage and use system for any specific application. The net warming impact will also depend on how many and what specific fossil fuel uses are displaced by hydrogen.

As outlined in Chapter II, the vast majority of present-day commodity hydrogen is used to make ammonia and methanol or to refine petroleum: about 10 million metric tons of commodity hydrogen are produced in the United States per year and an additional 3 to 4 million metric tons are generated internally in the petroleum refining and chemical industries. Most hydrogen today is produced on-site or close to the point of use. Due to this proximity between the production and consumption of hydrogen, leaks are estimated to be small. In these settings, the main concern regarding leaks has typically been safety, because hydrogen is an explosive gas. As a result, leak detection is currently oriented to detect large leaks. Conversely, information about the prevalence of low-level leaks that pose little safety risk is sparse. However, estimates of such leaks exist in the academic literature and in the hydrogen industry.

There are four separate stages where hydrogen can leak:

1. During production, where the potential for leaks varies by method of production.
2. During transport to the point of use, where the potential for leakage depends upon whether the hydrogen is in the form of a compressed gas or cooled to a liquid.
3. During storage at the point of use or in bulk long-duration storage for future use.
4. From the equipment and facilities where it is ultimately used, such as trucks, fuel cells, steel plants, and electricity-generating stations.

Figure III-2 shows total hydrogen leak estimates, including production, delivery to the use location, and at the point of use. Estimates are provided by three sources, since they differ somewhat between leak estimation methodologies:

- Fan *et al.* (2022): this report is from the Columbia University Center on Global Energy Policy.
- Cooper *et al.* (2022): this report was used to fill gaps in Fan *et al.* (2022).
- Esquivel-Elizondo *et al.* (2023): a literature review which was used for minimum and maximum hydrogen leakage estimates.

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[27] Ocko and Hamburg 2022

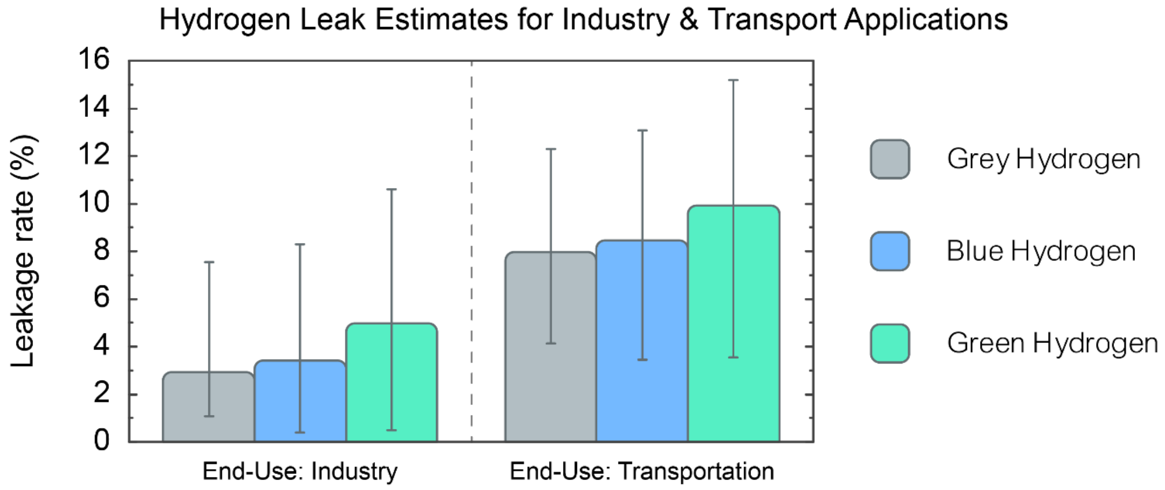

Figure III-2: Estimated value chain hydrogen leak rates for industrial and transportation applications using grey, blue or green hydrogen. Asymmetric error bars represent minimum and maximum leak estimates. Industry estimates include leaks during hydrogen production, compression, pipeline transport, salt cavern storage, and use in industry. Transport estimates include leaks during hydrogen production, compression, tube trailer transportation, above-ground storage, and use in vehicles. Median estimate calculated assuming the leak rate in each step is independent of the others.
Sources: Fan et al. *2022 for median values when available. Cooper* et al. *2022 for values unavailable in Fan* et al. *2022. High and low estimates based on Esquivel-Elizondo* et al. *2023.*

Figure III-2 considers three different hydrogen production methods and two end uses. As the figure demonstrates, each of these factors influences leakage rates. Between production methods, grey and blue hydrogen are based on steam methane reforming (SMR); grey hydrogen refers to standard SMR operation, whereas blue hydrogen adds a carbon capture and storage that removes some of the carbon dioxide that is produced by SMR. The third evaluated production method is green hydrogen, which uses electricity to split water into hydrogen and oxygen. Although each production method is discussed in more detail in Chapter IV, we will briefly highlight their main leakage mechanisms here, using the literature survey performed by Esquivel-Elizondo *et al.* (2023).

For grey hydrogen, minor leaks may occur through orifices and seals in pipework and equipment. Additional leakage may occur if hydrogen lines are purged for maintenance, troubleshooting or gas monitoring activities. Purging activities may be vastly reduced in newer plants, because purged gas can be flared off (combusted). Flaring reduces hydrogen leaks overall, but combustion is never 100% efficient, so that some fraction of flared hydrogen will still be emitted as hydrogen. We found no estimates of the efficiency of hydrogen flaring. Natural gas flaring is often assumed to be 98% efficient; however, measurements indicate that it is, in practice, about 90% to 92% efficient.[28] Hydrogen burns in a far wider range of concentrations in air than natural gas (4% to 75% hydrogen in air compared to 7% to 20% for natural gas); this makes the hydrogen flame more difficult to control, which may reduce flaring efficiency.[29] Thus, some amount of hydrogen leakage is inevitable for hydrogen. This statement also holds true for blue hydrogen, which possesses all of the aforementioned leak pathways, and also

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[28] Brandt *et al.* 2022

[29] Koestner 2021

includes the possibility of residual hydrogen being present in the CO_2 capture stream. Such hydrogen will likely leak into the atmosphere after CO_2 is separated for storage.

Different leakage pathways exist for green hydrogen.[30] This production method may suffer minor leakage through electrolyzer casings and pipework, but most leakage is associated with purging and venting. More specifically, electrolyzer pipework is vented during start-up and shutdown, and small amounts of hydrogen can also be present in an electrolyzer's oxygen stream that is typically vented. Hydrogen can also leak during the purging that occurs during hydrogen purification, although such leakage can be prevented.

As highlighted earlier in this chapter, hydrogen leakage also depends on transport, storage and end use. Thus, Figure III-2 considers two value chains: industry and transportation. For industry, we assume that hydrogen is transported by pipeline and then stored in underground salt caverns (see Chapter V) before use. For transportation, we assume hydrogen to be transported by tube trailer and stored above-ground before use. Between these two end uses, transportation has the highest leakage rate, mainly due to increased leakage rates during gas storage and usage. Industry leak rates are lower, and Arrigoni and Bravo-Diaz (2022) note that industry aims to reduce leaks by about one-third by 2030.

Figure III-2 does not show leaks related to cryogenic hydrogen production, transport, and storage. Cryogenic hydrogen handling refers to hydrogen being cooled to extremely low temperatures (253 below zero Celsius or 423 below zero Fahrenheit) to condense it into a liquid. It is much denser in this form, making it potentially more suitable for use in some applications such as aircraft, where low energy density per unit volume is infeasible. However, all cryogenic containers continuously absorb ambient heat when storing the hydrogen, which causes the hydrogen to slowly boil off during storage. To prevent pressure build-up in the storage container, the gaseous hydrogen must be captured and used, or vented, or flared. Hydrogen leaks in cryogenic transport are estimated to be very high – in the 10% to 20% range; the industry target is to reduce that to 4% to 5% by 2030.[31] Even at that target level, it would be necessary to capture and use the hydrogen or flare it to prevent significant warming impacts (see section d and e).

Thus, as our discussion of Figure III-2 indicates, there are many potential leakage pathways along the hydrogen value chain. The amount of leakage can vary significantly for each of these leakage point, which means that leakage estimates above are *highly* uncertain. For example, our low-range industry leakage estimate for green hydrogen is 0.48%, whereas the high-range estimate is 10.62%: 22 times higher. The issue of uncertainty in leak evaluation, which Esquivel-Elizondo *et al.* (2023) discuss in much more detail, indicates the need for real-life testing to estimate hydrogen leaks. Importantly, the wide range of leakage estimates suggests that leaks should constantly be monitored when building and operating hydrogen infrastructure. Such monitoring requires extremely sensitive hydrogen detectors that can remotely sense hydrogen in the parts-per-billion range; these sensors are currently being piloted by parties like the Environmental Defense Fund and Aerodyne (Arrigoni & Bravo-Diaz (2022). Widespread availability of this type of sensors would be crucial, because, as the following sections will explain, high leakage rates can significantly reduce the potential climate benefits of hydrogen. When quantitatively discussing leakage rates, our report will use the median range in Figure III-2, unless otherwise noted.

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[30] Esquivel-Elizondo *et al.* 2023

[31] Arrigoni and Bravo-Diaz 2022

d. Estimating warming impact from hydrogen leak and methane leak interactions

The previous discussion suggests that anthropogenic sources of hydrogen (direct and indirect) already exert a warming impact of roughly 1% of total global warming. Increases in net hydrogen emissions would add to this warming impact if all other things remain equal. The increase in hydrogen use will likely result in an absolute increase in hydrogen leaks, which will have an impact on atmospheric methane concentrations. Specifically, hydrogen produced by steam methane reforming with or without CCS ("blue hydrogen" and "grey hydrogen" respectively) increases overall methane leaks since it increases the demand for natural gas. Methane is an even stronger greenhouse gas than hydrogen (when averaged over a 20-year time frame), but both gases have a warming impact far greater than CO_2. As a result, the net warming impact of using and producing hydrogen is highly dependent on the rate of hydrogen leaks and the rate of methane leaks added up over the entire production, processing, transportation, storage and use system for any specific application. The total warming impact will also depend on how many and what specific fossil fuel uses are displaced by hydrogen.

To illustrate these concerns, we consider grey, blue, and green hydrogen production with different rates of methane and hydrogen leaks associated. For two of these methods (green and blue hydrogen), Bertagni *et al.* (2022) calculated whether substituting fossil fuels (on a Btu for Btu basis[32]) for hydrogen would result in an increase or decrease of atmospheric methane concentrations. This substitution *decreases* the amount of methane that is emitted when producing, transporting and using these fossil fuels because less natural gas is used as a fuel. But making blue hydrogen increases natural gas use for CCS and hence methane leakage; any hydrogen leaks would also *increase* atmospheric methane concentrations. When trying to assess the overall increase or decrease in methane concentrations, the paper's authors considered different levels of hydrogen substitution for fossil fuels, ranging from 0% to 100% of fossil fuel use. Grey hydrogen was not included in the calculations.

Figure III-3 summarizes their results for substituting 15% of global fossil fuel usage by three hydrogen leak rates (1%, 5%, and 10%) and two natural gas leak rates, 1% and 2%. The estimates in Figure III-3 are global but correspond approximately to the DOE estimate that 10% to 25% global carbon emissions are in areas where there is "strong potential to adopt clean hydrogen."[33]

To contextualize the results in Figure III-3, one should note that the best estimate of methane leaks in the United States at present is about 2.7%.[34] The Biden Administration has set a goal of 30% methane leak and venting reductions from the 2020 level by the year 2035.[35] Hence, it may underestimate warming impact to use a 2% leak estimate for the period up to the early 2030s. In the longer term, beyond 2040, it is possible that the methane leak rates could decline to 1% if industries and governments implement vigorous efforts that extend well beyond current plans. Reducing leakage below 1% will take both a large decrease in natural gas use, a corresponding reduction in production,

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[32] That is, differences in efficiency between fossil fuel use and hydrogen use for the same application are not taken into account.

[33] DOE 2023a, p. 7, Figure 1

[34] The compressors needed to pressurize natural gas for pipeline transport use natural gas as the fuel. The 2.7% leakage rate as a fraction of natural gas sold takes that into account as well as the leakage in the pipeline infrastructure. The leakage rate based on production is about 2.3% (Alvarez *et al.* 2018); this amounts to 2.7% of the amount sold when leaks and natural gas use for compression and transport to the point of use are taken into account.

[35] White House Fact Sheet 2021

remediation of leaks from retired wells and monitoring to ensure leaks have been reduced or ended. The rest of this analysis assumes a range of 1% to 2% methane leaks, with some discussion about the implications of lower leak rates as well as the estimated national average leak rate of 2.7%. It is worth noting that hydrogen produced from methane with CCS can only qualify under DOE's definition as clean if the 1% methane leak rate is met if the 100-year warming potential is used for methane; with a 20-year warming potential it would not qualify until leaks are reduced below 0.6% (rounded) (see Figure IV-4 and IV-5).

Figure III-3 shows net atmospheric methane concentration changes when hydrogen replaces 15% of the global fossil fuels on a one-for-one energy basis; natural gas is currently about 30% of that mix. The figure does not account for differences in efficiency of use. In the United States, natural gas is about 40% of the fossil mix, so displacing that mix will tend to push methane concentrations a little lower than what is shown in Figure III-3. Exact amounts need application-specific calculations because hydrogen use can be more efficient than fossil fuel use, offsetting some of the losses in its production.

Notably, Figure III-3 indicates that blue hydrogen *increases* atmospheric methane concentrations at all hydrogen leakage rates if the corresponding methane leakage rate is above 1%. In contrast, substituting 15% of fossil fuels with green hydrogen reduces atmospheric methane concentrations if the hydrogen leakage rate is 1% or 5%. In fact, this green hydrogen decreases atmospheric methane levels as long as less than 9% of the hydrogen leaks (Bertagni *et al.* 2022). The estimates in Figure III-3 therefore indicate that, at realistic hydrogen and methane leakage rates, green hydrogen benefits atmospheric methane levels, whereas blue hydrogen generally does not.

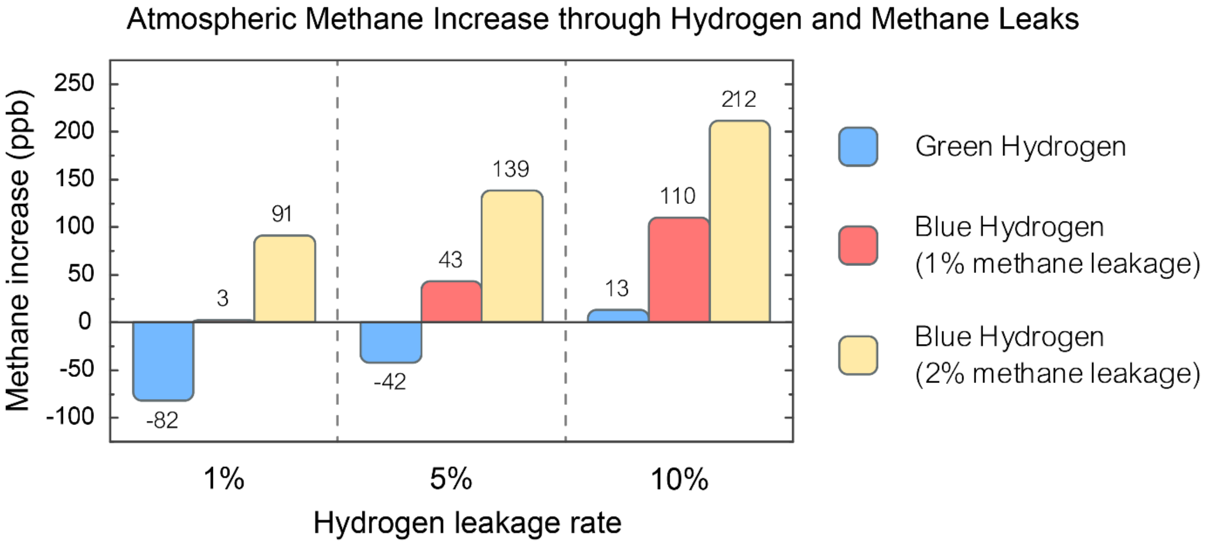

Figure III-3: Net change in global methane concentrations corresponding to three hydrogen leak rates, two assumptions about hydrogen production, and two methane leak rates. Level of hydrogen use corresponds to displacing ~15% of global fossil fuel use. Values of methane concentration changes read off from Figure 3 of Bertagni et al. *2022.*

The assumption underlying Figure III-3 in Bertagni *et al.* is that there is a one-to-one replacement on an energy basis of hydrogen energy for fossil fuel energy. This is reasonable for an overall average calculation; it is also reasonable for many specific uses, such as fuel cell trucks compared to diesel trucks (see Chapter V). However, the impact of replacing fossil fuels by hydrogen in any specific sector will depend on the efficiency with which it is used relative to efficiency of the corresponding fossil fuel use.

Nonetheless, some overall conclusions can be drawn from the analysis in Bertagni *et al.* as represented in Figure III-3.

Figure III-3 does not tell the entire global warming story of hydrogen leaks and warming, because it only considers hydrogen's effect on atmospheric methane concentrations: as noted in section b, this effect only covers 50% of hydrogen's warming impact. An additional ~30% of the warming impact of hydrogen is estimated to result from the creation of water vapor in the stratosphere when hydrogen is oxidized there. Another 20% of warming stems from the creation of tropospheric ozone. These effects are not captured in Figure III-3, which therefore underestimates the climate effects of hydrogen leaks.

Fortunately, the overall warming effect of hydrogen and methane leakage can be estimated by considering the 'global warming potential', which will be discussed in Section e of this chapter.

e. Radiative forcing and global-warming potential

The foregoing sections analyze the warming impact in terms of radiative forcing from methane and CO_2 in the atmosphere and in terms of net changes in methane concentrations. Warming impact is also assessed via global-warming potentials (GWPs); these are relative measures that are, by convention, estimated by setting the value of the GWP of CO_2 equal to 1. In other words: the GWP expresses how much CO_2 would produce the same amount of warming as a given amount of another greenhouse gas (such as methane) during a specific time span. GWPs allow greenhouse gases to be compared to each other and provide regulators with an approximate yet readily understandable way to add up the impacts of accumulated greenhouse gases as a single CO_2-equivalent number.

Global warming potential is calculated as an integrated impact over a period of time; conventionally it has been 100 years, a round number chosen decades ago when the time period of severe climate change was judged to be longer than it is today. The period of integration matters, because different gases are removed from the atmosphere at varying rates: CO_2 persists for centuries, while methane has an atmospheric lifetime of about 13 years (which means that about 90 percent is removed from the atmosphere by chemical reactions over a period of 30 years). Since the climate crisis has developed faster and more intensely than modeled in the 1990s, it is important to complement the usual use of the 100-year GWP with a 20-year GWP. This shorter time frame is especially relevant now that the target date for achieving "net-zero" emissions for limiting global average temperature rise to 1.5 °C is around year 2050. This does not negate the importance of the longer time frames over which methane becomes less prominent relative to CO_2; the 100-year time frame is critical because CO_2 is the principal greenhouse gas forcing global warming and its lifetime is very long.[36] We make reference to both as appropriate, but use the 20-year GWP for most of this report because of its link to the 2050 net-zero target date.

Factoring hydrogen into this framework presents a scientific challenge because hydrogen is not a direct greenhouse gas: as discussed above, it exerts its influence indirectly by impacting the hydroxyl radical concentration and increasing both stratospheric water vapor and tropospheric ozone concentrations. An additional complication is that the lifetime of hydrogen is much shorter than methane; the largest warming impact of hydrogen is via its impact on methane concentration in the atmosphere. But despite

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[36] As noted in IPCC 2013 (Chapter 8, pp. 711-712), "There is no scientific argument for selecting 100 years compared with other choices. The choice of time horizon is a value judgement because it depends on the relative weight assigned to effects at different times."

the complexities, the GWP metric is easily understandable and provides a straightforward comparison of the reduction of warming due to technical measures or changes in policy.

Since hydrogen's lifetime is short (roughly 2 years), the integration period and integration method matter a great deal. Normally, GWPs are calculated by assuming a single pulse of the gas in question emitted at a point in time. But almost the entire impact of hydrogen occurs within five years of a pulse release. A different result is obtained if one calculates the 20-year GWP of hydrogen relative to CO_2 by assuming a steady rate of emissions instead of a pulse emission. Neither reflects rising hydrogen use adequately; however, a GWP calculated assuming continuous emissions is more representative than a pulse emission. This type of GWP has been estimated to be as high as 40 on a global basis by Hauglustaine *et al.* (2022) but they estimate a value of 34 for the northern hemisphere, very close to the value of 33 we use here, based on continuous emissions as estimated by Ocko and Hamburg (2022).[37]

A review of Ocko and Hamburg (2022) confirmed that the 20-year GWP of hydrogen is considerably greater than CO_2 and significantly less than methane.[38] The review also corroborated the Ocko and Hamburg results for shorter time frames on the order of 10 or 20 years. They also point out that over a 100-year period, the impact of hydrogen would be significantly lower, a result that derives from the short lifetime of hydrogen.[39] Duan and Caldeira also stress that, if hydrogen and methane emissions are stopped, their warming impact declines rapidly because their lifetime is much shorter than that of carbon dioxide. This rapid reduction is strongest for hydrogen because of its much shorter lifetime of about 2 years. Limiting leaks of both methane and hydrogen and prioritizing leak reduction for both gases would therefore yield benefits at all time frames including, most importantly, over the next two decades over which the vast majority of greenhouse gas emissions need to be stopped.

It is useful to consider the impact of hydrogen leaks alone because a certain level of leaks, hydrogen could by itself create a large enough impact that it would not be considered 'clean' under the DOE's standard on that topic. That standard has two elements (which are discussed in more detail in Chapter IV):[40]

- Two kilograms of CO_2-eq greenhouse gas emissions per kilogram of hydrogen at the production site;
- Four kilograms of CO_2-eq emissions on a "well-go-gate" basis including, onsite and offsite emissions.

Figure III-4 shows the warming impact of various hydrogen leak levels alone, independent of any other warming impact from hydrogen production. The 4 kg CO_2-eq per kilogram of hydrogen is also shown for reference. The warming impact of hydrogen is evaluated at its 20-year warming potential of 33, as discussed above.

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[37] Mixing of gases between the northern and southern hemispheres takes time with the lag dependent on the differences between sources and sinks. For instance, the CO_2 concentration in the southern hemisphere reached 400 ppm in 2016 while it reached that level in the northern hemisphere in 2014-15 – see The Conversation 2016.

[38] Duan and Caldeira 2023

[39] Ocko and Hamburg 2022

[40] DOE Standard Guidance 2023

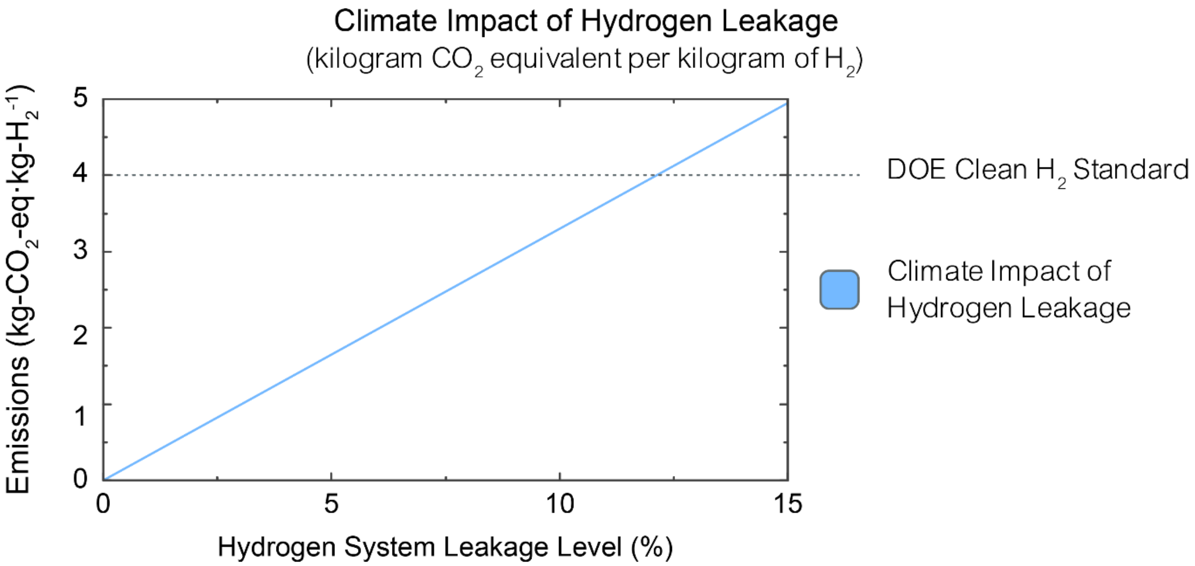

Figure III-4: Warming impact of hydrogen leaks compared to the DOE clean hydrogen standard. 20-year GWP of hydrogen (=33) used for the computations. Fossil fuel emissions for corresponding to a kilogram of hydrogen would be about 11 kilograms of CO_2-equivelent; see text.

Figure III-4 shows that at a leak rate of more than 12%, the warming impact of hydrogen leaks alone would exceed the DOE standard guidance for clean hydrogen, even if the greenhouse gas emissions from production were zero. (However, the DOE standard guidance does not take the warming impact of hydrogen leaks into account.) While a 12% leaks rate is rather high, it does occur notably when hydrogen is condensed to a liquid (at very low temperatures) and stored in that form.[41] Compressed hydrogen transport, storage, and leak rates are typically lower than 10% for the entire system.[42] In addition, there is a great deal of uncertainty in hydrogen leak estimates and likely a large variation between similar hydrogen installations.[43] If it is to contribute to decarbonization, the hydrogen production must necessarily involve low leak levels.[44]

The works by Hauglustaine *et al.* (2022), Ocko & Hamburg (2022), and Duan & Caldeira (2022) each approximate the near-term detrimental climate effects of hydrogen and methane throughout hydrogen's supply chain. While somewhat different in their assumptions about hydrogen and methane leaks, the modeling in these papers is consistent in the conclusions that green hydrogen has the largest climate benefits, though they decline somewhat with increasing hydrogen leaks. For instance, a 60% efficient fuel cell for producing peaking power using green hydrogen produced on site and compressed using renewable energy would have essentially no warming impact in the absence of leaks (Chapter IV). If leaks were 10%, the warming impact would be about 170 grams CO_2-equivalent per kWh, compared to 900 grams for coal-generated power and somewhat less for natural gas (depending on the level of methane leaks).

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[41] Arrigoni and Bravo-Diaz 2022

[42] Fan *et al.* 2022

[43] Esquivel-Elizondo *et al.* 2023

[44] This caveat would not be applicable if large reservoirs of natural hydrogen that can be economically recovered are found. The necessity of keeping leaks low to avoid negative climate impact would still apply.

All in all, as this chapter illustrates, the issue of hydrogen leakage is complicated. We therefore summarize the importance of leakage as follows:

- Hydrogen leaks of a few percent or more significantly reduce the climate mitigation impact of using hydrogen to displace fossil fuels.
- By themselves, leaks have to be very high to eliminate the climate benefit altogether relative to fossil fuels. The exact value at which this negation takes place would depend on the use of hydrogen being considered but leaks above 15% should probably be considered a priori unacceptable both for climate and safety reasons. In any case, leaks above 12.1% would by themselves result in greenhouse gas impact above the 4 kg CO_2-eq per kg H_2 DOE threshold for clean hydrogen. (Though it should be noted that DOE has not included hydrogen leaks in its definition of “clean hydrogen” and uses a 100-year warming potential for methane.)
- The net climate benefit of using hydrogen depends on the balance of hydrogen leaks, the greenhouse gas emissions associated with hydrogen production, and the time horizon of the analysis. These benefits are discussed in detail in Chapter IV and visualized in Figure IV-4 and Figure IV-5, but several highlights of this analysis include:
    - Green hydrogen would generally have some climate benefit, with the amount depending on the application;
    - The blue hydrogen climate benefit would depend on the rate of methane leaks and hydrogen leaks as well as the efficiency of carbon capture and the extent of permanent sequestration of the carbon captured. The prospects of a climate beneficial outcome or blue hydrogen are poor, as discussed in Chapter IV and Chapter VI.
    - Grey hydrogen, which has about 8.6 kg CO_2-eq per kg hydrogen excluding methane leaks and about 14.5 kg CO_2-eq with 2.7% methane leaks (and 20-year GWP for methane) would generally not have a climate benefit except in cases where hydrogen use efficiency is much higher than fossil fuel efficiency; the only example of this among the applications we have examined is steel production from iron ore where hydrogen replaces coke (Chapter VI).

IV. Hydrogen Production and Its Impacts

Hydrogen as a commodity is currently produced almost entirely from other, primary, energy sources, mainly natural gas and coal. The 10 million tons a year produced in the United States mainly use natural gas as a feedstock for steam methane reformation to hydrogen, with coal gasification being a secondary method, as can be seen in Figure IV-1. Only about one percent of U.S. hydrogen is produced using electrolysis – that is by using electricity to split water, H_2O, into hydrogen and oxygen. The global picture is similar to the United States, except that coal use is much higher at 22%; natural gas is 76%, with the rest being electrolysis.[45]

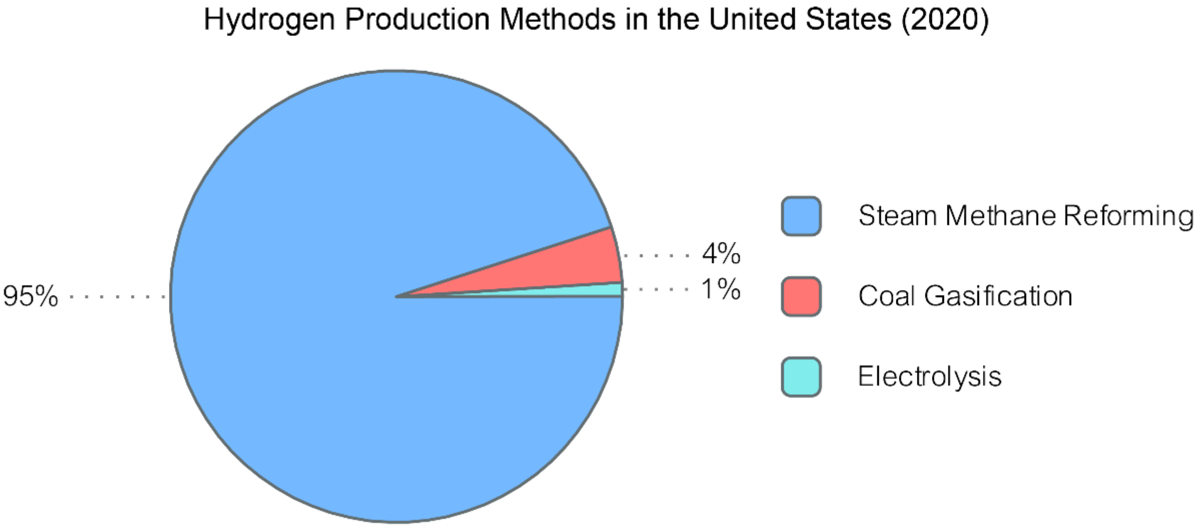

Figure IV-1: Technologies used for hydrogen production in the United States. Source: DOE 2020.

All hydrogen production depicted in Figure IV-1 currently involves greenhouse gas emissions, because 99% of it is derived from fossil resources. Even the remaining 1% of electrolysis is not carbon-free, because it typically uses grid electricity and the U.S. grid is not carbon-free. As discussed below in section IV.a.ii, electrolysis does have the potential to be emission-free when powering it with renewable energy. The resulting hydrogen is defined as "green hydrogen"; it is the one approach that is already developed that would have very low lifecycle greenhouse gas emissions. For this type of hydrogen, a key issue its cost, which the DOE's "Hydrogen Shot" program aims to reduce from $5/kg in 2021 to $1/kg by about 2031.[46]

As noted in Chapter II, at present, hydrogen is mainly produced for use in industrial applications, (including petroleum refining) and making chemicals, of which ammonia is the most prominent. However, hydrogen as a part of a strategy for decarbonizing the energy system is proposed to be used primarily as an energy source to replace fossil fuels in industry, in transportation, in buildings, and in electricity generation. In this context, it would be a *secondary* energy source: an energy carrier that is made from other, *primary* energy sources, which are available from natural reservoirs, like fossil fuels in the ground or solar energy which streams into the Earth. That would change if natural hydrogen sources are found and exploited; in that case hydrogen would also be a primary energy source. Such sources of

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[45] DOE 2020, page 5

[46] DOE 2021

hydrogen are currently being explored.[47] This chapter focuses both on methods of producing hydrogen from other primary energy sources, as well as the potential and implications of naturally available hydrogen. We will call this "geologic hydrogen" rather than other commonly used names like "gold hydrogen" and "white hydrogen".

a. Hydrogen production processes

We consider the following approaches and energy sources for hydrogen production:

- Steam methane reforming
    - Natural gas without CCS ("grey" hydrogen) and with CCS ("blue" hydrogen)
    - Landfill gas
    - Biogas
- Coal gasification with and without CCS
- Water electrolysis with various electricity sources
    - The electricity grid – national average carbon intensity ("yellow" hydrogen)
    - Solar and/or wind ("green" hydrogen)
    - Nuclear ("pink" hydrogen)
- Biomass conversion
- Solar thermochemical process
- Naturally occurring hydrogen (geologic hydrogen)
- "Orange" hydrogen resulting from water injected into suitable hydraulically-fractured geologic formations.

We first examine fossil-fuel-based and electrolytic hydrogen production, then hydrogen from what is often called "renewable natural gas" – that is landfill gas and biogas – and from biomass, and briefly the nascent solar thermochemical process.

i. Steam Methane Reforming

As noted, steam methane reforming (SMR) is by far the most established and widespread hydrogen production method in the world, the more so in the United States. At present it is done without carbon capture and sequestration (CCS), or carbon capture, usage and storage (CCUS): two processes that capture carbon dioxide and respectively store or utilize it. The Department of Energy funded a multi-year demonstration project for coupling carbon capture with SMR, which demonstrated the feasibility of 90% CO_2 capture.[48] The CO_2 was used for stimulating petroleum production in a process called 'enhanced oil recovery', which is also the use to which CO_2 from the vast majority of CCS projects is put.[49]

Steam methane reforming of natural gas is based on the fact that the main constituent of natural gas – on the order of 95% or more – is methane, CH_4. The hydrogen atoms in methane as well as hydrogen atoms in steam (H_2O) constitute the basis of a large-scale chemical production process at the core of

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[47] Ohnsman 2023

[48] Argonne's GREET model uses 96% CO_2 capture (Argonne 2022). IEEFA 2023 captures ranges between 30% and 80% in contexts outside enhanced oil recovery (rounded).

[49] Air Products 2018

which are two chemical reactions. The first is the steam methane reforming step which converts methane and steam to carbon monoxide and hydrogen:

$CH_4 + H_2O + \text{heat} \rightarrow CO + 3H_2$ (IV-1)

Since carbon monoxide can be oxidized with a release of energy, a second reaction, known as the water gas-shift reaction, is advantageous:

$CO + H_2O \rightarrow CO_2 + H_2 + \text{heat}$ (IV-2)

The net result of the two reactions is that one molecule of methane and two molecules of water are transformed into four molecules of hydrogen and one molecule of carbon dioxide, as shown in equation (3), where the masses of the inputs and outputs in grams (per mole) are also indicated.

CH_4 (16 grams) + 2 H_2O (36 grams) $\rightarrow$ 4 H_2 (8 grams) + CO_2 (44 grams) (IV-3)

In a perfect (stoichiometric) reaction, depicted above, one kilogram of methane would yield slightly over half a kilogram of hydrogen, which represents the energy equivalent of about half a gallon of gasoline. However, there is a net need for heat to accomplish the requisite chemical reactions. This heat is generally provided by natural gas. The overall energetic efficiency of producing hydrogen is about 70%; this means about 40% more natural gas use than the ideal case, with correspondingly larger CO_2 emissions. Finally, electricity is needed to operate the steam methane reforming equipment, including the pumps and compressors; this reduces the efficiency slightly.

An alternative to steam methane reforming is autothermal reforming, which uses pure oxygen. More specifically, in a typical methane reforming process, the heat to produce steam is created by burning natural gas in air and the methane is reacted with the steam. In auto-thermal reforming, methane and steam are reacted with pure oxygen, which is extracted from the air in a separate process. The process is said to enable better carbon capture, among other things, and is proposed for larger scale hydrogen production from natural gas.[50] Electricity use per kilogram of hydrogen is higher with autothermal reforming; however, natural gas use is somewhat lower. Auto-thermal reforming emissions compared to steam methane reforming depend in significant measure on the source of electricity. DOE's National Energy Technology Laboratory estimates that greenhouse gas emissions from autothermal reforming with CCS are about 24% larger than SMR with CCS (5.7 vs. 4.6 kg CO_2-eq per kg H_2), using grid electricity with national electricity CO_2-eq emission rates.[51] Grid electricity-related emissions were estimated to be 1.2 kg CO_2-eq per kg H_2 more with auto-thermal reforming than with SMR, and therefore account for a little more than the entire difference.[52] These estimates indicate that neither technology would meet the DOE clean energy standard guidance of 4 kg CO_2-eq per kg H_2, even if the less stringent metric of a 100-year global warming potential for methane is used. (See Chapter III for more discussion of global warming potentials.)

ii. Electrolysis

Besides being present in methane, hydrogen atoms are also abundant in an even more ubiquitous molecule: water (H_2O). Water can therefore be used to create hydrogen, which is most commonly done using a process called electrolysis. In contrast with thermochemical reactions like steam methane

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[50] Air Liquide 2023
[51] NETL 2022
[52] NETL 2022 (Exhibit 3-52). The NETL estimates use a 100-year global warming potential for methane.

reforming that use high temperatures or pressures to convert one molecule into another, electrolysis uses electricity as an energy source. It does so by separating the water-splitting reaction into two half-reactions separated from one another in space in “half cells”, which are connected to one another electrically, using a device called an ‘electrolyzer’ (Figure IV-2). We describe electrolyzer technologies in some detail since (i) this is the approach for making green hydrogen, and (ii) some of the required catalysts are critical materials.

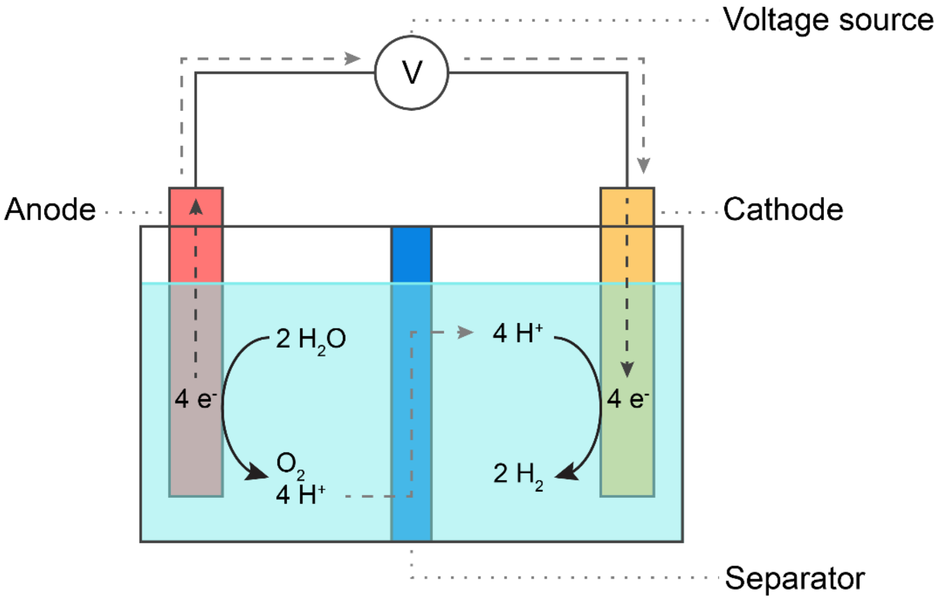

Figure IV-2: Schematic of an electrolyzer.

Two half-reactions occur in electrolyzers. The first one of these half-reactions is referred to as the ‘oxygen evolution reaction’. This reaction converts water (H_2O) into molecular oxygen (O_2) and positively charged hydrogen atoms (H^+) that are either referred to as hydrogen ions or protons.[53] This is seen on the left side of Figure IV-2. The process releases electrons (e^-), and is depicted as follows:

$$2\ H_2O \rightarrow O_2 + 4\ H^+ + 4\ e^-$$

The oxygen evolution reaction occurs on the surface of an electrode in one of the half cells: a piece of conductive material (often a metal), which touches the water and is connected to a voltage source. For the oxygen evolution reaction, this electrode is referred to as the ‘anode’. When water is converted into molecular oxygen and protons, the electrons pass from the water into the anode and travel through the external voltage source as an electrical current. Ultimately, these electrons move towards another electrode, called the ‘cathode’. At the same time, the protons migrate to the cathode. These protons travel through the water and through a membrane or diaphragm. Upon reaching the cathode, the protons and electrons combine to form molecular hydrogen:

$$4\ H^+ + 4\ e^- \rightarrow 2\ H_2$$

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[53] The formation of H^+ occurs under acidic conditions. Some electrolyzers operate under different conditions, using alkaline liquids or molten salts instead of an acidic solution. These electrolyzers do not form H^+, which will be noted when discussing such electrolyzers in detail in the following sections.

This reaction is called the ‘hydrogen evolution reaction’, and occurs on the surface of a second electrode in the second half cell. Combined, the oxygen and hydrogen evolution reaction form the overall water splitting reaction:

$2\ H_2O \rightarrow 2\ H_2 + O_2$

It is important to note that a mixture of hydrogen and oxygen would be highly explosive. Furthermore, if hydrogen were able to travel to the anode or oxygen were able to reach the anode, the hydrogen and oxygen would be consumed; such consumption would reduce the overall efficiency of an electrolyzer. For these two reasons, electrolyzers contain a separator membrane or diaphragm (Figure IV-2) that ensures the produced hydrogen and oxygen from the cathode and anode do not mix.[54]

Water splitting is an energetically uphill reaction, requiring a minimum voltage of 1.23 V as an energy input. Most of the electrical energy is stored in the produced hydrogen molecules as chemical energy: each hydrogen molecule stores 2 electrons that produce 1.23 V when released, which means that a kilogram of hydrogen holds 33 kWh of energy. Thus, hydrogen molecules can act as an energy storage medium. However, not all of the electrical energy input is converted into H_2, because real-life electrolyzers require more than 1.23 V to operate. This additional voltage is required because there are energy barriers involved in making hydrogen. In order to overcome these barriers, an extra voltage needs to be applied, which is known as the ‘overpotential’. These overpotentials can range anywhere between 0.3 V and 1.2 V.

The actual required voltage depends on several variables, such as energy losses due to electrical resistance in the electrolyzer and at which current the electrolyzer operates. This hydrogen production rate is variable, because a higher voltage can be applied to the electrolyzer in order to pass more electrons and therefore produce more hydrogen. Such increased hydrogen production comes at the cost of a higher overpotential (driving force), and therefore how much more electricity than the theoretical minimum is used within the electrolyzer.

In other words, the amount of overpotential relates to the overall efficiency of an electrolyzer; the overpotential energy is not stored in hydrogen molecules as chemical energy. For example, an overpotential of half a volt yields an electrolyzer efficiency of 71%.[55] Electrolyzers can operate anywhere between 1.53 V to 2.43 V corresponding to efficiencies between 51% and 80%. The efficiency of an electrolyzer is a critical parameter because it determines the required electricity input to make hydrogen. Such inputs are the main cost of producing hydrogen by electrolysis.

Various types of electrolyzers exist at different levels of technological readiness. The most important include:[56]

- alkaline electrolyzers;
- proton-exchange membrane electrolyzers;
- anion-exchange membrane electrolyzers;

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[54] Fuel cells, which perform the reverse reaction, converting hydrogen and oxygen back to water while generating electricity, also have a membrane for the same reason.

[55] A 0.5-volt overpotential means an operating voltage of 1.73 volts; the efficiency therefore equals 1.23/1.73 = 0.711 = 71% (rounded).

[56] Shiva Kumar and Lim 2022

- solid oxide electrolyzers.

Each of these electrolyzers has different performance characteristics, which determine their overpotential and energy efficiency. For example, all of these electrolyzers have so-called ‘catalysts’ on their cathodes and anodes. The catalysts allow the hydrogen and oxygen evolution reactions to happen more easily, lowering the barrier to each reaction and consequently reducing the overpotential required to produce hydrogen. Catalysts are an essential component of an electrolyzer, so considering them explicitly is important. Such scrutiny is particularly relevant because catalysts can represent a significant capital expense, and because some catalysts are rare metals, with attendant mining and processing environmental impacts. Each type of electrolyzer uses different catalysts.

The four electrolyzer types will briefly be described below; they are illustrated in Figure IV-3.

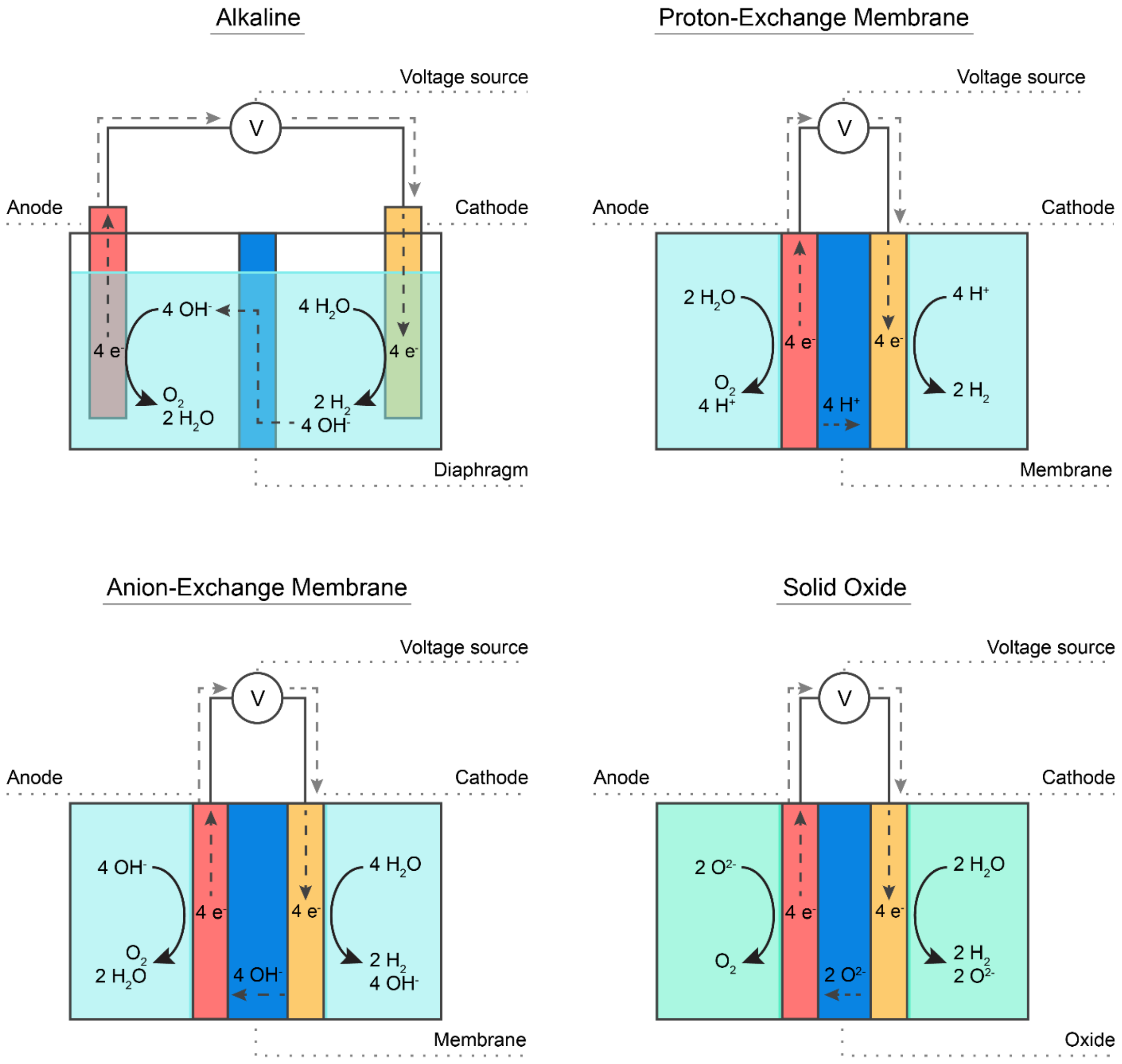

Figure IV-3: Schematic depictions of 4 common electrolyzer types.

Alkaline electrolyzers are the most technologically mature electrolyzer technology. As the name implies, these electrolyzers use a highly alkaline (basic) water solution (pH value of 14 or higher). This does not change the general operating principles of the electrolyzer, but it does subtly affect the details of the process. Specifically, at basic operating conditions, protons (H^+) are present in extremely low concentrations, so they cannot participate in water splitting in the manner that was described above. Instead, water splitting occurs in a two-step process, via hydroxide ions (OH^-) as follows:

$4\ H_2O + 4\ e^- \rightarrow 2\ H_2 + 4\ OH^-$

The hydroxide ions travel to the anode, where the oxygen evolution reaction occurs in the form of:

$4\ OH^- \rightarrow 2\ H_2O + O_2 + 4\ e^-$

The net result of these reactions is the same as for water splitting in acidic conditions:

$2\ H_2O \rightarrow 2\ H_2 + O_2$

Alkaline electrolyzers operate between 70 °C (158 °F) and 90 °C (194 °F), have a lifetime of about 60,000 hours (6.8 years), and use nickel-coated steel as both their cathode and anode; the nickel functions as the catalyst in both cases. The cathode and anode reside in different compartments that are separated by a diaphragm that is made out of zirconia (although asbestos was used as a diaphragm in the past). This diaphragm separates the hydrogen that forms on the cathode from the oxygen that forms on the anode, but does so imperfectly, allowing some gas crossover. This crossover can cause explosive hydrogen-oxygen mixtures to form at low operating currents, thus imposing a minimum safe operating current onto alkaline electrolyzers.[57] Because this diaphragm adds to the physical distance between cathode and anode, most alkaline electrolyzers suffer from electrical resistance between these two electrodes. This resistance limits the maximum current that can be passed in an alkaline electrolyzer, which in turn reduces the hourly hydrogen production capacity of the device. In addition, alkaline electrolyzers are not well-suited for operation at varying currents, which might be required in situations where electrolyzers respond to the shifting availability of renewably generated electricity. This inability to operate flexibly is due to the aforementioned lower operating current limit (for safety) and higher operation limit (determined by internal electrical resistance).

Other electrolyzer types are designed in ways that circumvent these resistance and flexibility problems. They do so by substituting a membrane for the diaphragm separator. Each side of this membrane is then coated with a cathode or anode catalyst, which eliminates the need for ions to travel through a resistive liquid medium (see Figure IV-3 above). This membrane is approximately as thick as a human hair, so the distance between anode and cathode (and, consequently, the electrical resistance) is made as small as possible. Reflecting this small membrane thickness, electrolyzers using such membranes are sometimes referred to as "zero-gap electrolyzers". Electrolyzer membranes come in two types: proton-exchange and anion-exchange. These membranes selectively transport protons (H^+) or hydroxide ions (OH^-), respectively.

Proton-exchange membranes are used in electrolyzers that are typically referred to as "PEM electrolyzers". The electrolyzers operate between 50 °C (122 °F) and 80 °C (176 °F), and have lifetimes of 50,000 hours to 80,000 hours (5.7 years to 9.1 years at 100% operating capacity). Though less mature than alkaline electrolyzers, PEM electrolyzers have several benefits. For example, they can operate with

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[57] Brauns and Turek 2020

pure water feedstocks, thus avoiding the highly corrosive basic inputs that alkaline electrolyzers use. In addition, their electrical current and corresponding hydrogen production rate can be varied more rapidly than alkaline electrolyzers can. This property makes proton-exchange membrane electrodes more suitable for variable electricity inputs, characteristic, for instance, of wind and solar generation. One drawback is that these electrolyzers typically contain noble-metal catalysts: platinum on the cathode side and iridium on the anode side of the membrane. The use of such scarce resources poses possible constraints to scaling PEM electrolyzer technology (see "mining and processing section" below).

This noble-metal limitation is circumvented in anion-exchange membrane electrolyzers, which are often abbreviated as "AEM electrolyzers". These devices aim to combine the flexibility of proton-exchange membrane electrolyzers with the commonly available nickel- and iron-based catalysts that are used in alkaline electrolyzers. AEM electrolyzers operate between 40 °C (104 °F) and 60 °C (140 °F), and are technologically less mature than both alkaline and proton-exchange membrane electrolyzers. In fact, anion-exchange membranes are not widely commercialized yet, face issues involving inferior operation when using nickel- and iron-based catalysts, and a lifetime that is currently limited to only around 10,000 hours (almost 14 months). Given the importance of reducing the need for rare, expensive catalysts, various companies and academic institutions are working on improving and scaling up this type of electrolyzer.

The fourth and final relevant electrolyzer technology is the solid oxide electrolyzer. Instead of a membrane, this electrolyzer contains a thin ceramic material, like zirconium oxide, that conducts oxide ions (O^{2-}). As such, the hydrogen and oxygen evolution reactions look different in this electrolyzer type:

$2\ H_2O + 4\ e^- \rightarrow 2\ H_2 + 2\ O^{2-}$
$2\ O^{2-} \rightarrow O_2 + 4\ e^-$

These two reactions still add up to the conventional water splitting reaction that is outlined at the beginning of this section. However, the reactions involve the transport of O^{2-} ions through a solid oxide. This transport requires high temperatures: solid oxide electrolyzers operate between 700 °C (1292 °F) and 950 °C (1942 °F). As a result, solid oxide electrolyzers require high heat inputs; their high temperature makes them very suitable for coupling with industrial process that generate waste heat – similar to combined heat and power plants common in the chemical industry that use natural gas as a fuel. The high temperature also improves the water splitting rate, which places a lower demand on the catalyst materials. Commonly used catalysts for this type of electrolyzer include nickel-based materials on the cathode and so-called rare-earth element-containing perovskite materials on the anode. Main issues with solid oxide electrolyzers include a limited lifetime of approximately 20,000 hours (2.3 years) and the production of high-temperature oxygen when splitting water: high-temperature oxygen is very corrosive to gas lines.

Since each electrolyzer cell is limited in capacity, a number of cells are combined into a stack in a manner not much different than many batteries are combined into battery packs. Such stacks form the basis of industrial electrolyzer plants that can take in megawatt-scales of electricity.

iii. Comparison of steam methane reforming and electrolysis

We can now compare the climate impact of the various approaches to using fossil fuels and electricity to produce hydrogen. We include the emissions from the energy source used to make the hydrogen (electricity, natural gas, etc.) and methane leaks associated with that energy source. As discussed in the Chapter III above, we have used a 20-year global warming impact of 33 for hydrogen in order to get a consistent basis for deriving a single CO_2-equivalent climate impact value for each method.

Figure IV-4 shows the warming impact of producing one kilogram of hydrogen (roughly the energy equivalent of a gallon of gasoline) by various methods. Natural gas leaks are estimated at 2.7% of natural gas sales, based on a comprehensive scientific evaluation of the data.[58] Natural gas is around 95% methane;[59] therefore, the rate of natural gas leakage and venting translates into an almost equal rate of methane emissions.

The Biden administration as well as various corporations have announced targets for reduction of natural gas leaks. We have therefore used two methane leak rates to assess the warming impact of hydrogen production: 2% and 1%, which are both lower than the current average leakage rate of 2.7%. These lowered numbers may be achieved in the longer term if methane leakage targets from the natural gas system are tightened. The same leakage rate is also used for the portion of electricity that is generated from natural gas. Given the variation in leakage rates, it will be important to use site-specific data to determine whether particular projects meet the DOE clean hydrogen standard guideline of 4 kg CO_2-eq per kg H_2 and, if they do not, the specific reduction in natural gas leakage rates needed to meet that threshold.

Figure IV-4 shows CO_2-equivalent emissions for grey and blue hydrogen (steam methane reforming without and with CCS, respectively) at two different methane leak rates and green hydrogen produced with wind and/or solar electricity. Both the 100-year and 20-year warming potentials for methane are used, since the former is still in official common use, despite the net-zero target date of 2050.

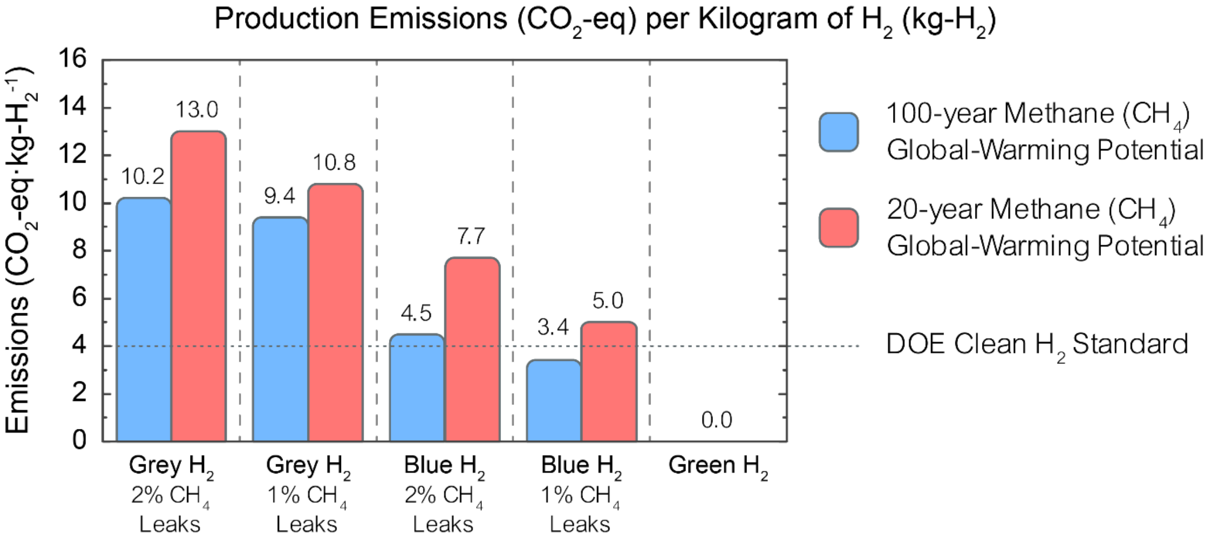

Figure IV-4: CO_2-eq warming impact for various means of hydrogen production, including methane leaks. Source: Argonne 2022, Figure 2 and Table 4, and IEER adjustment for 20-year methane GWP. We used a 20-year methane GWP of 82.5; Argonne used a 100-year GWP of 30 (reflected in the blue bars).

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[58] Alvarez *et al.* The authors estimate a national average leak rate of 2.3% based on natural gas production. When the natural gas used for the compression needed to push it through pipelines to final customers and natural gas leaks are taken into account, the leak rate based on sales of natural gas to customers is about 2.7%.

[59] There are other gases, like CO_2 and hydrogen sulfide, mixed in in varying quantities in natural gas as it comes out of the ground; the raw gas is processed to eliminate these gases so that what is put into pipelines is almost all methane with a few percent of other hydrocarbons.

The results in Figure IV-4 should be evaluated against the guidance specified in the Clean Hydrogen Production Standard published by the Department of Energy pursuant to the Bipartisan Infrastructure Act.[60] This guidance states that hydrogen can be qualified as 'clean' if it meets the following two emissions criteria.

- Emissions at the hydrogen production site are below 2 kilograms of CO_2-eq per kilogram of hydrogen.

- Total 'well-to-gate' emissions are below 4 kilograms of CO_2-eq per kilogram of hydrogen. These well-go-gate emissions are the sum of the aforementioned production site emissions and emissions that occur upstream. Such upstream emissions include emissions involved in obtaining and transporting feedstocks for hydrogen production. Specific downstream emissions such as "processes associated with ensuring that CO_2 produced is safely and durably sequestered" are also included.[61] Notably, downstream emissions are only included if they relate to the production of hydrogen. Other downstream emissions that occur during distribution, storage and usage of hydrogen are not considered.

The guidance is not a regulation but provides targets for production technologies to achieve. In addition, it is not all-encompassing: the Department of Energy's flow diagram accompanying the two criteria above makes clear that the embedded emissions in the equipment, such as pipes and pumps and steel and concrete structures are not included.[62] While quite unusual for "lifecycle emissions," the omission is not unreasonable as a first approximation in the hydrogen context because hydrogen would be displacing fossil fuels, including the capital equipment requirement to produce, deliver, and use them.

Figure IV-4 includes a line showing the 4 kg CO_2-eq per kg H_2 "lifecycle" limit as a line to enable comparison of each production option with it. The term "lifecycle" normally includes the greenhouse gas emissions associated with the production of the equipment and infrastructure; however, in this case the Department of Energy has limited the term to the greenhouse gas emissions at the production site and upstream of it. Capital investment-related CO_2-eq emissions are not included; we have followed this approach in Figure IV-4. For instance, the embedded energy in the capital equipment for producing and transporting natural gas or producing solar panels (and the materials in them) is not included. The main reason for this omission is that the estimates rely on the most comprehensive model for hydrogen-related emissions so far: the GREET model created by DOE's Argonne National Laboratory, which excludes embedded energy. Consequently, electrolytic hydrogen is shown as having no emissions. Taking capital investment-related emissions into account may add on the order of 1 kg CO_2-eq (rounded) emissions to the totals shown in Figure IV-4.[63]

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[60] DOE Standard Guidance 2023

[61] DOE Standard Guidance 2023, page 3

[62] DOE Standard Guidance 2023, Figure 1, page 4

[63] Unfortunately, no comprehensive recent (less than five years) estimate of lifecycle emissions for electricity sources is available. Older estimates (by the National Renewable Energy Laboratory) for nuclear power and wind are ~0.013 kg CO_2-eq per kWh and for solar 0.043 kg CO_2-eq/kWh. While nuclear technology materials and construction remain about the same, since the basic designs in use are the same (light water reactors), solar and wind electricity costs have declined. Solar technology in particular has changed and become far more efficient, as has wind, to a lesser extent. An order or magnitude estimate of 0.01 kg CO_2-eq/kWh for capital equipment is a reasonable; this amounts to 0.5 kg CO_2-eq for electrolysis using wind, solar, or nuclear. In addition, the hydrogen producing equipment (steam methane reforming, electrolysis stacks) and associated construction must be factored in.

Importantly, neither Figure IV-4 nor the Clean Hydrogen Production Standard include the effect of hydrogen leaks. This omission is notable because, as Chapter III illustrates, hydrogen leakage can have significant climate impacts. To illustrate this fact, Figure IV-5 displays the effect of hydrogen leakage on the well-to-gate emissions of blue and green hydrogen production. Figure IV-5 uses a 20-year GWP for methane at two levels of methane leaks (1% and 2% leak rate). It takes the same approach for hydrogen leak (1% and 5% leak rate; 20-year GWP). When including additional hydrogen leaks, blue hydrogen never meets the DOE clean hydrogen standard guideline. We should note in this context that hydrogen production that would be part of the Department of Energy's hydrogen hub program would not be required to meet the clean hydrogen guideline; rather it should be able to "[d]emonstrably aid the achievement of the clean hydrogen production standard."[64]

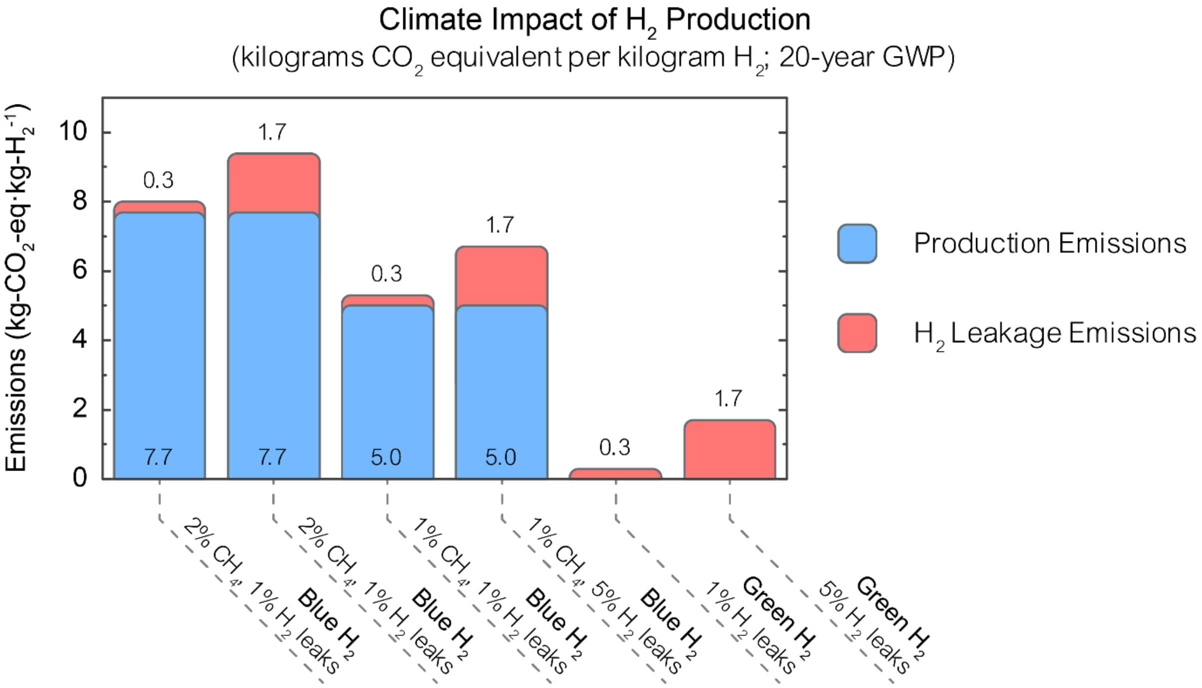

Figure IV-5: Warming impact per kilogram of blue and green hydrogen production, with 20 year GWPs for methane (82.5) and hydrogen (33). Numbers based on Figure IV-4.

Figure IV-4 and Figure IV-5 show that only electrolysis with renewable energy gives a result that (easily) meets draft DOE clean hydrogen standard. Steam methane reforming with the methane coming from natural gas exceeds the standard by more than a factor of two. When CCS is added to this process, most of the carbon dioxide is presumed to sequestered (and hence not emitted). This "blue" hydrogen meets the DOE standard if a 100-year global warming potential is used for methane and if one accepts the very high estimate of 96% for CCS used by Argonne. It exceeds the DOE standard by more than 50% if the 20-year GWP for methane is used. In this context, we note that almost 90% of the impact of methane emitted in 2023 will be felt by or before the year 2050. It also exceeds the DOE standard even with a 100-year GWP for methane if CO_2 sequestration is around 85% or less – which appears much more likely

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[64] OCED 2022

given industry CCS experience outside of using CCS to stimulate oil production.[65] All-in-all it is reasonable to conclude that blue hydrogen cannot meet the DOE standard in the foreseeable future even with drastically reduced natural gas leaks compared to the prevailing average level.

iv. Landfill gas, biogas, and biomass for hydrogen production

Landfill gas, biogas, and biomass are often treated under the rubric of "renewable energy" but usually without the rigor that would correspond to the imperative to reduce greenhouse gas emissions to zero and remove some of the accumulated atmospheric greenhouse gases from past emissions. These are three very different kinds of raw materials that could be used for hydrogen production, and biogas and biomass themselves can also refer to many different kinds of source fuels. But they are represented as renewable primary sources that, with CCS, could result in negative CO_2 emissions.[66] We begin this brief review of the matter with a definition of renewable energy in IPCC5:[67]

> **Renewable energy (RE):** Any form of energy from solar, geophysical, or biological sources that is replenished by natural processes at a rate that equals or exceeds its rate of use.

Trash that is landfilled is a human construct that is not renewed by natural processes. Thus, even by this rather limited definition, trash is not renewable; nor is any product derived from it, including landfill gas. This does not settle the issue of whether landfill gas should be collected and used, and if so, for what purposes. Argonne National Laboratory uses landfill gas that is cleaned of impurities, like hydrogen sulfide, as "[t]he default option for RNG [Renewable Natural Gas]" in its hydrogen production model.[68]

It is not the purpose here to examine all the ins-and-outs of using landfill gas to make hydrogen: it can be one potential feedstock. But we do note that there are alternatives to landfilling organic wastes, where they are consumed by anaerobic bacteria, which results in the production of a mixture of methane, CO_2, and other gases, including hydrogen sulfide. For instance, composting avoids most methane production because it is aerobic. While the carbon in the organic material is oxidized to CO_2 (similarly to when landfill gas is burned), the nutrients are retained, and can substitute for chemical fertilizers, provided the input organic matter is clean. Specifically, the nitrogen in the compost displaces synthetic nitrogen fertilizers, which are produced from ammonia, one of the main uses of hydrogen produced from natural gas today. Moreover, organic fertilizers can be used in low-till organic farming, stimulating deep soil carbon sequestration. The resulting reduction in ammonia requirements would also decrease the need for hydrogen to produce such ammonia. However, fully assessing the interplay between landfill gas, composting, regenerative agriculture and fertilizer needs is a complex analysis that is beyond the scope of the present report; we predominantly raise this example because a holistic scope is needed in order to make the best use of available resources for climate and environmental protection.

There is also the issue of methane emissions from existing landfills, where the option of separating and composting organic wastes no longer exists. In such cases, the option of using cleaned landfill gas for

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[65] Schlissel and Juhn 2023

[66] See Argonne 2022 and NETL 2022, for instance.

[67] IPCC 2014, page 1261. IPCC5 does not specify the period over which the energy used must be regenerated by natural processes. This is a serious gap in the definition that can (and does) allow old growth trees to be cut down and burned as "renewable" energy. A sound definition would require regeneration of the energy within one year of its use or less. See discussion in Makhijani 2016, page 75-78.

[68] Argonne 2022

hydrogen production, likely at a distant location (as assumed in Argonne 2022) must be compared with other uses such as onsite electricity generation or combined heat and power in order to evaluate relative merits from a climate perspective.

The above definition of renewable energy indicates that, under certain circumstances, on-farm biogas production with use of the residues on the farm may be considered as renewable provided synthetic chemicals and inputs – which are not replenished by natural processes – are not used to on the farm. If they are, then the lifecycle analysis becomes much more complex.

IPCC5 renewable energy criteria, quoted above, indicate that biogas using waste created in Concentrated Animal Feeding Operations cannot be considered renewable. Further, the vast scale of nutrient loading in the residues from biogas production make it costly and difficult to apply it to farms without risk of polluting nutrient runoff.

Finally, hydrogen can also be produced from woody biomass. Biomass can, in principle, be renewable if all carbon and nutrient considerations as well as overall land use assessments are carried out. This is because biomass carbon can be replenished by natural processes, but it is subject to nutrient, soil carbon conservation, and other considerations. The National Energy Technology Laboratory has carried out an assessment of using woody biomass for jet fuel production. In that assessment, new cropland and pastureland would be created elsewhere to replace the land used for planting pine forests for woody biomass.[69] The assumptions about which land is converted to crop and pastureland uses and how that is done are critical to the overall carbon balance. No general statement about renewability, much less sustainability can be made on the basis of general assumptions.

Overall, the process of using biomass for hydrogen production is essentially similar to that for using coal, except that biomass must be dried by a process called torrefaction before it can be efficiently converted. NETL 2022 examines an option of coal and biomass co-firing with CCS as a possibility for a negative carbon emissions hydrogen production system. NETL 2022 estimates a net negative warming impact of about 1 kg CO_2-eq/kg H_2.[70] Biomass hydrogen production with CCS would also result in intensive water use as well as nitrogen oxide (NO_x) emissions. *Consequently, if the hydrogen is used in fuel cell cars, the overall nitrogen oxide emissions per mile would be comparable to typical gasoline cars. In contrast, the particulate emissions per mile would be roughly an order of magnitude larger than gasoline cars.*[71] Instead of being widely dispersed, the hydrogen related NO_x and particulate pollution would occur in one location, impacting the community and ecosystems where hydrogen production takes place.

v. Using existing low-carbon electricity sources for hydrogen production

About three-fifths of U.S. electricity production comes from burning fossil fuels – almost all natural gas and coal. This means that the decarbonized portion – wind, solar, hydropower, geothermal energy and nuclear energy – is already supplying loads. In effect, we can consider that 40% of electrical loads are already decarbonized.

Use of nuclear energy for making hydrogen has been proposed; indeed, it is part of the DOE's hydrogen hub program. The DOE is already supporting a pilot project to produce hydrogen using nuclear electricity

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[69] NETL 2015

[70] NETL 2022, Exhibit 5-5.

[71] Calculated from Exhibit 5-3 NETL 2022 and the following standards for new vehicles – 0.03 grams/mile of NO_x and 0.003 grams per mile of particulate matter emissions. The EPA emission standards are at https://www.epa.gov/greenvehicles/light-duty-vehicle-emissions viewed on April 1, 2023.

from an existing power plant at the plant site – the Nine Mile Plant in upstate New York.[72] This means that the loads that that portion of the nuclear plant was supplying will now be using electricity from the grid.

This small pilot project is making supposedly zero-emissions hydrogen from an existing nuclear plant. However, it is a new load; therefore, the grid the grid is now required to supply about 10,100 MWh of electricity to the loads previously supplied by the Nine Mile plant.[73] This would entail about 2,000 metric tons of additional CO_2 emissions, taking into account the overall profile of current electricity supply, which includes import of a significant amount of zero-emissions hydropower from Canada. Notably, 99% New York's fossil fuel generation is from natural gas, which are paired with methane leaks and added warming. Thus, the total added emissions to replace the nuclear generation used for the pilot hydrogen plant with the average New York supply would add almost 3,400 metric tons of CO_2-eq to New York State's greenhouse gas inventory to produce about 190 metric tons of hydrogen.[74] This means an *overall system emissions estimate of 18 kg* CO_2*-eq per kg* H_2*, even though the emissions at the hydrogen production electrolyzer on the nuclear plant site are zero. This greenhouse gas intensity is worse than the 14.6 kg* CO_2*-eq that characterizes grey hydrogen production on average, using a 2.7% methane leak rate and a 20-year warming potential in all calculations.* In reality, the net statewide impact may be better or worse, depending on the actual mix of replacement power. It may well be worse since the largest spare capacity in the state is in its natural gas combined cycle and natural gas boiler plants; they operated at only about 30% capacity factor in 2021. Were natural gas generation alone to replace the nuclear generation diverted to hydrogen production, the added emissions would be about 8,000 metric tons per year or more than 40 kg CO_2-eq per kg hydrogen.[75]

The same reasoning would apply if existing renewable energy resources or hydropower resources were diverted to produce electrolytic hydrogen. The outcome would be worse in most other locations since New York has a smaller fraction of fossil fuel generation than most places and because New York also imports hydroelectricity from Canada. This means that the generation to be replaced has, on average, lower emissions than would be typical were hydrogen to be produced at most other nuclear plants, such as the Calvert Cliffs plant in Maryland.

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[72] Office of Nuclear Energy 2023

[73] Constellation 2023

[74] Calculated as follows. Constellation 2023 states that 560 kg of hydrogen would be produced per day, using 1.25 MW of power for an electrolyzer onsite. This electricity, (10,074 MWh per year, assuming 92% average capacity factor) would be consumed in this new load leading to the same generation requirement from other sources in the New York grid. The average emissions in the New York grid in 2021 were 0.226 metric tons CO_2 per MWh over the entire generation about 45% of which is natural gas; almost all the rest is hydropower, nuclear, and renewables. Factoring in imports, the average emissions were 0.197 mt/MWh. If the supply mix remains the same (entailing added imports), the total greenhouse gas emissions due to the diversion of nuclear power to the new hydrogen load amount to about 3,400 metric tons to produce about 190 metric tons of hydrogen per year. The emissions from natural gas generation alone were 0.456 mt CO_2/MWh, to which the impact of methane leaks must be added.

[75] New York had about 19,700 MW of natural gas capacity that could serve as replacement supply. Total natural gas generation from these plants was about 51.7 million MWh – a capacity factor of about 30%. This was the largest available replacement capacity in the state. New York State electricity data are from the state's electricity profile at https://www.eia.gov/electricity/state/newyork/state_tables.php

vi. Geologic Hydrogen and Orange Hydrogen

There has been increasing interest in the possibility that significant amounts of usable hydrogen exist underground. This subterranean hydrogen is referred to by several names, including ‘natural’, ‘geologic’, ‘white’ and ‘gold’ hydrogen. One natural hydrogen source was accidentally discovered in Mali (in West Africa) in the course of drilling for water.[76] It was determined that the gas coming from the water drilling borehole was 98% hydrogen. In 2012, the gas was used to fuel a 300-kilowatt electric generator that supplied the village of Bourakébougou with its first electricity. In this report, we will use the term “geologic hydrogen” for this potential resource.

It would change the prospects of hydrogen significantly if large amounts of economically producible hydrogen were found underground, especially if they were regenerated naturally, thus providing a renewable fuel. Recognizing the potential of geologic hydrogen, the Department of Energy’s ARPA-E program recently announced $20 million of available funding towards geologic hydrogen research.[77] This funding, for which applications were due on October 24, 2023, is split between two topics: “Production of Geologic Hydrogen Through Stimulated Mineralogical Processes” and “Subsurface Engineering for Hydrogen Reservoir Management”. The former of these topics aims to produce hydrogen underground by injecting water into iron-rich mineral formations, which could then convert the water into hydrogen. This stimulated hydrogen production is not strictly geologic. Called “orange hydrogen” its source is the water injected into the formations which would be hydraulically fractured (“fracked”) to allow the catalytic chemical reactions to take place.[78] Will consider geologic hydrogen and orange hydrogen in turn.

- Geologic hydrogen

The specifics of the potential, environmental impact, economic implications, and even political context of geologic hydrogen would depend greatly on how widely the resource is distributed. If it can be produced economically close to the point of use in quantities that are suitable for the particular application, it would likely displace hydrogen production from other energy sources. Conversely, if geologic hydrogen is found in large reservoirs in specific biogeochemical settings in a limited number of countries, its political economy might come to resemble the global oil economy. The extent of local hydrogen production from other energy sources would depend largely on the cost of production from the large reservoirs. Geologic hydrogen could therefore be a promising source of a gas that would otherwise be energy-intensive to produce, but research surrounding the location and magnitude of underground reservoirs is still in its infancy. Consequently, the commercial viability of geologic hydrogen is far from certain.

Likewise, the climate impact of geologic hydrogen remains an open question for the following reasons:

- Geologic hydrogen can contain a variety of impurities from relatively benign gases like nitrogen (N_2) to potent greenhouse gases like methane (CH_4);
- Once drilled, hydrogen may leak from the geologic hydrogen reservoir, in a manner similar to methane with attendant warming and safety implications;

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[76] Hand 2023
[77] ARPA-E 2023
[78] Osselin *et al.* 2022, Figure 1 and text

- If the geologic hydrogen is tight formations similar to shale natural gas, then fracking may be necessary to liberate economic amounts of hydrogen;
- Large geologic hydrogen reservoirs, should they exist, may be remote from the places where hydrogen would be used, with leaks attendant upon transport of compressed hydrogen by pipeline or cryogenic hydrogen by ship or rail;
- Geologic hydrogen that are abandoned because they are no longer economical may nonetheless continue to leak, with consequent warming impact.

Currently, there is a large knowledge gap surrounding the climate impact of geologic hydrogen. It may well vary significantly from one hydrogen deposit to another, much in the manner of natural gas leaks. For instance, there is considerable uncertainty about the presence of gaseous impurities in associated with geologic hydrogen and their impact on the carbon intensity of geologic hydrogen. An initial climate impact estimate study was published recently.[79] The study models the greenhouse gas emissions for a hypothetical hydrogen drilling operation. It includes emissions from a variety of sources, including infrastructure buildout and methane and hydrogen leakage: two sources that would not be considered under the DOE Clean Hydrogen Production Standard.[80] We highlight several important findings from the study:

- A significant emission source is ‘embodied emissions’, which refer to: “emissions associated with steel and cement production for those materials consumed during the [well] construction process.” These emissions make up approximately 0.2 kg CO_2-eq per kg H_2 of the numbers listed in the following paragraph.
- The electricity source for drilling significantly impacts process emissions, much like it does for electrolytic hydrogen.
- The presence of methane contaminations may drastically increase the emissions intensity of geologic hydrogen. This methane needs to be separated from the hydrogen and can be reinjected, combusted or flared; each of these methods has a different impact.

If the aforementioned factors are favorable, the carbon intensity of geologic hydrogen approximately 0.4 kg CO_2-eq per kg H_2 when drilling a mixture of 85% H_2, 12% N_2 and 1.5% CH_4.[81] (Percentages are given as mole fractions.) A less favorable source gas mixture of 75% H_2, 22.5% CH_4 and 2.5% N_2 would yield emissions of 1.5 kg CO_2-eq per kg H_2. In very unfavorable cases like extracting a 50:50 mixture of methane and hydrogen, emissions could be as high as almost 5 kg CO_2-eq per kg H_2. Leaks of hydrogen from the reservoir due to the fact of drilling into it or if it has been fracked, or leaks during transportation (especially in the case of cryogenic hydrogen) would add to these warming totals. As a result, the climate impact of geologic hydrogen is at present highly uncertain; it would need careful evaluation once there are more data on the geologic hydrogen formations, their locations and sizes, and the methods of production needed to extract the hydrogen economically. Thus, although hydrogen reservoirs with favorable compositions could meet the DOE Clean Hydrogen Production Standard of 4 kg

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[79] Brandt 2023

[80] DOE Standard Guidance 2023

[81] The model spreadsheet associated with Brandt (2023) lists an overall hydrogen leak rate of 1.7% and a methane leakage rate of 2.0%. For both gases, it uses a 100-year global warming potential, which are listed as 5 and 25, respectively. These values are lower than those used in the present report.

CO_2-eq per kg H_2 if leakage rates are low and favorable GWP values are used when evaluating emissions, geological hydrogen should not be considered 'clean' by default.

Orange hydrogen

"Orange hydrogen" is similar to geological hydrogen in the sense that it is pumped from the ground, but is different in one key regard: whereas geological hydrogen is generated by natural processes underground, orange hydrogen only forms after humans decide to induce its creation. In fact, the hydrogen in orange hydrogen would be derived from the water that is injected into suitable geologic formations that stimulate hydrogen production. Fracking of the formation appears to be necessary to inject the water and recover the hydrogen. For this reason, orange hydrogen is also referred to as "stimulated hydrogen". Consequently, orange hydrogen is *not* "natural" hydrogen. Rather the hydrogen forms when the injected water reacts with the geologic formation that serves as the catalyst for underground water splitting. This type of hydrogen requires fracking and its associated environmental and seismicity issues. In addition, the hydrogen produced may be consumed by microbiota resulting in loss of hydrogen and a consequent increase in water requirements per unit of hydrogen produced.[82] If the consuming bacteria are 'methanogenic' they would eat both H_2 and CO_2, resulting in underground methane (CH_4) formation as well;[83] such methane would later need to be separated from the orange hydrogen and could leak into the atmosphere to exacerbate global warming. Finally, leaks of hydrogen may be considerably greater than with geologic hydrogen, and may occur in a manner similar to the larger leaks associated with fracked natural gas. Thus, despite an expansive claim that "Orange hydrogen is the new green,"[84] the reality is that orange hydrogen will require large amounts of water; may have significant environmental justice issues; and for all that may not meet the DOE's Clean Hydrogen Production Standard guidance. In short, our preliminary analysis would place orange hydrogen in a very different category than green hydrogen or even geologic hydrogen produced without fracking.

vii. Early-stage processes

Thermochemical hydrogen production

Hydrogen can also be produced from water without electrolysis by splitting water directly at high temperatures in the presence of suitable catalysts. This is called "solar thermochemical" hydrogen production: it is part of the Department of Energy's suite of hydrogen research and development programs. The method requires concentrating solar energy using mirrors. Figure IV-6 shows one possible scheme being researched at the National Renewable Energy Laboratory.

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[82] Osselin et al. 2022

[83] Hemme and Van Berk 2018

[84] This is the title of Osselin *et al.* 2022.

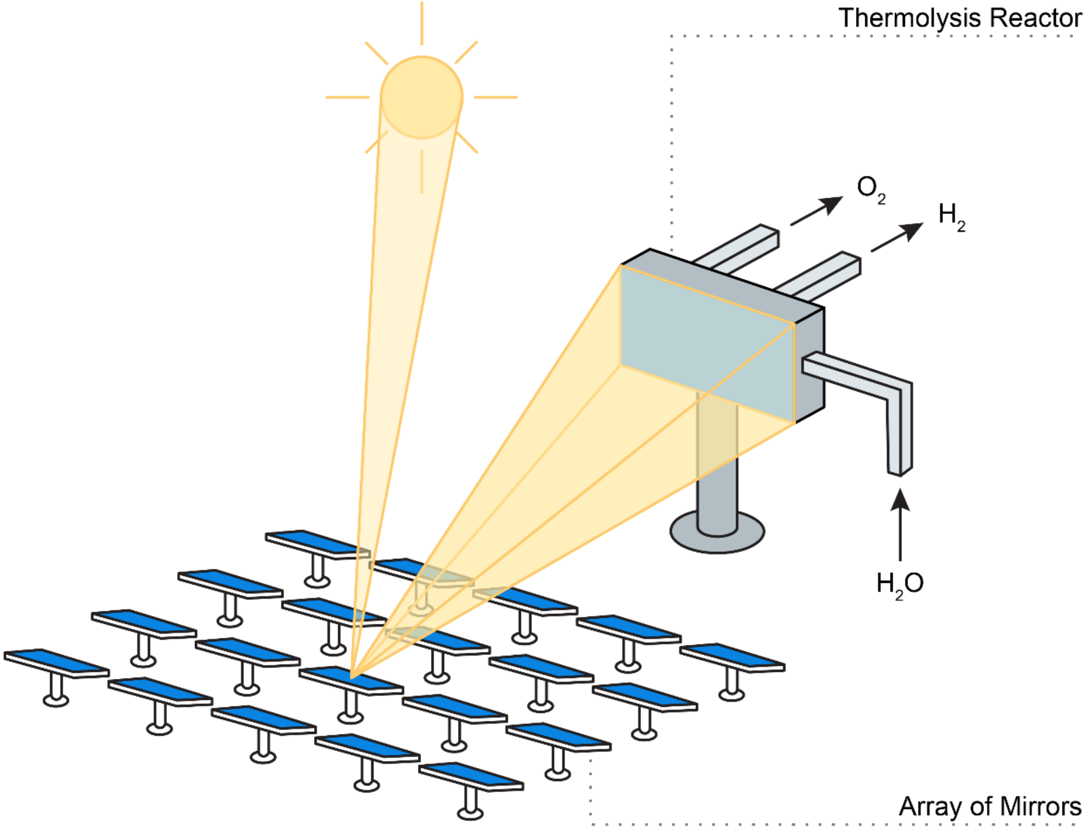

Figure IV-6: A proposed scheme for thermolytic hydrogen production using concentrating solar energy. Source: Based on NREL 2022a.

The scientific principles of thermochemical hydrogen production have long been established. It is potentially more energy-efficient than solar electricity production, because solar thermochemical hydrogen production uses the solar spectrum more fully than photovoltaics cells do.[85] But there are significant challenges, including discovering suitable catalysts that will be durable at a cost that is low enough. The development of suitable low-cost methods of concentrating solar energy also poses major challenges.

The advantages of a successful effort are apparent, because a single step would convert solar energy into hydrogen, compared to the electrolysis route, which requires considerable investment in electricity production followed by another significant investment in electrolysis with attendant energy losses. Solar thermochemical production would be restricted to desertic and semi-desertic areas, with attendant likely requirements for hydrogen transport and difficult water supply issues, as well as similar land-use and ecological concerns as existing concentrated solar thermal systems. In addition, the problem of water resources in a desertic environment is likely to pose substantial technical, economic, and environmental justice issues.

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[85] NREL 2022a

Photoelectrochemical hydrogen

Sunlight can be converted to hydrogen in a single device without first producing electricity and then using that for electrolysis in a device that, in effect, combines the electricity and electrolysis steps. In the long term, this process could yield efficiencies as high as 22% conversion of sunlight to hydrogen.[86] However, at present, photoelectrochemical hydrogen production remains confined to the laboratory scale; key challenges include the development of sufficiently active and stable photocatalysts, as well as designing and scaling photoelectrochemical devices that are large enough for real-life applications.[87]

b. Water consumption and withdrawals

Water is an essential input for most hydrogen production processes, including the most common ones. In this section we analyze water issues associated with the following production processes:

1. Hydrogen made from natural gas without carbon capture – called “grey” (or “gray”) hydrogen;
2. Hydrogen made from natural gas with carbon capture and sequestration (CCS) – called “blue” hydrogen;
3. Hydrogen made by electrolysis (splitting water (H_2O) into hydrogen and oxygen gases using electricity)
    a. using renewable electricity (solar or wind) – called “green” hydrogen;
    b. using nuclear electricity – called “pink” hydrogen;
    c. using grid electricity – called “yellow” hydrogen.

Using electricity to recover hydrogen by splitting water into its component elements necessitates consideration of the water requirements for electricity generation; as discussed below, these can vary from essentially zero (wind-generated electricity) to very large (nuclear and other thermo-electric generation).

For each of these processes, the minimum feed water requirements arise from considerations of basic chemistry. This minimum water demand is called the ‘stoichiometric requirement’. In the case of methane (CH_4), half the hydrogen comes from methane and half from steam (H_2O); the production method is called “steam methane reforming” (SMR):

$CH_4 + H_2O \rightarrow CO + 3\ H_2$

$CO + H_2O \rightarrow CO_2 + H_2$

Combined, these reactions yield the following overall result (shown with molar masses for each input and output):

CH_4 (1 mole = 16 grams) + 2 H_2O (2 moles = 36 grams) $\rightarrow$ CO_2 (1 mole = 44 grams) + 4 H_2 (4 moles = 8 grams).

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[86] Jaramillo and Houle 2021

[87] Clarizia *et al.* 2023

This translates into 4.5 kilograms of water per kilogram of hydrogen, which is equivalent to 1.19 gallons (4.5 liters).[88]

For electrolysis, the net reaction is simpler; but as with SMR it also involves catalysts:

$2\ H_2O$ (2 moles = 36 grams) → $2\ H_2$ (2 moles = 4 grams) + O_2 (1 mole = 32 grams).

This equates to 9 liters (2.38 gallons) of water per kilogram of hydrogen.

Thus, the stoichiometric water requirement for electrolytic hydrogen per unit mass of hydrogen is double that for steam methane reforming. However, it should be noted that the actual raw water requirements for both steam methane reforming and electrolysis are higher than the aforementioned theoretical minimums, in large measure due to water purity requirements. Because input water streams require low concentrations of dissolved solids, any 'raw' water is processed to the required purity. Such purification results in some water being rejected.[89] The amount of rejected water depends on the purity of the input water. Consequently, a significant part of the variation in water withdrawal for steam methane reforming and electrolysis is due to the varying purity of the input water. The addition of carbon capture and sequestration – essential for "blue" hydrogen – increases water use significantly. Thus, converting a grey hydrogen site to a blue hydrogen site will, among other things, generally increase water requirements. This makes water requirements for green and blue hydrogen generally comparable.

An additional source of water consumption is the water that is required for producing the electricity needed for hydrogen production, because all methods of hydrogen production require electricity to power their equipment. Electricity is a small fraction of the energy for grey hydrogen and does not impact water use much, but the impact is increased when an energy-intensive CCS process is added for blue hydrogen.

In electrolysis, electricity is the energy source used to break apart the hydrogen-oxygen bond in H_2O. As a result, the water requirement for electricity production also becomes a major factor in the water intensity of electrolytic hydrogen. Water demands will be high when using grid electricity to do so, because most generation in the United States is "thermo-electric" (also called "thermal") electricity generation: a fuel is used to boil water into high pressure steam, which drives a steam turbine, which in turn drives the electricity generator. A schematic of thermo-electric generation, as exemplified by a pressurized water nuclear reactor, is shown in Figure IV-7. It shows how the steam that drives the turbine-generator set is produced and condensed so that the steam water can be used in a closed loop. A separate stream of water used in the condenser (bottom right half of Figure IV-7); the condenser water carries away the latent heat in steam and condenses the steam back into water. The process is the same for nuclear, coal-fired, and natural gas boiler power plants, though the boiling is differently arranged. Typically, about two-thirds of the energy in the fuel is transferred into the condenser water; this explains the large water requirements of thermo-electric generation.[90]

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[88] A kilogram of hydrogen is roughly equivalent in energy terms to a gallon of gasoline.

[89] The rejected water is often 2 to 4 times more concentrated in dissolved solids than the feed water, and can therefore generally be used for other purposes. It is therefore considered to be withdrawn, and not consumed. (See Section II.a and II.b.)

[90] Natural gas combined cycle plants use both a gas turbine and a steam turbine. They are much more efficient than coal or nuclear plants and, as a result, use much less water.

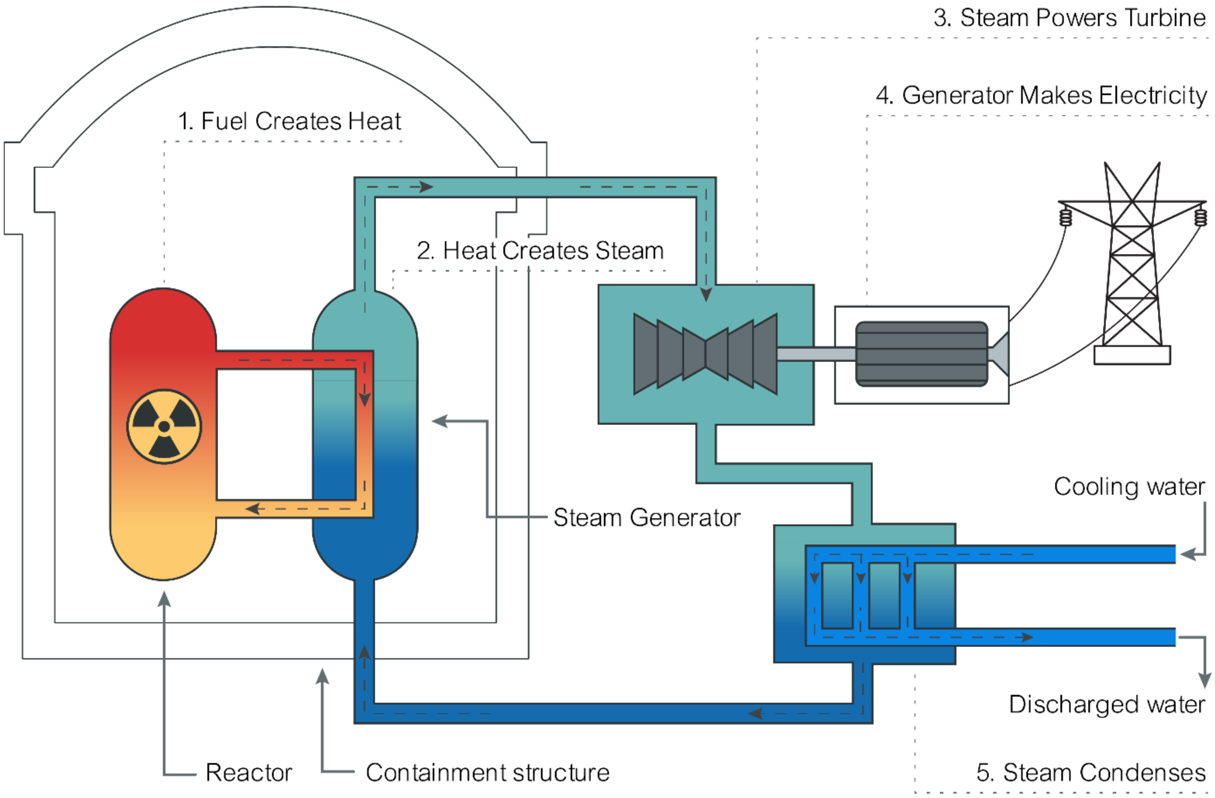

Figure IV-7: Schematic of a nuclear power plant, showing the condenser. Based on a Nuclear Regulatory Commission schematic at https://www.nrc.gov/images/reading-rm/basic-ref/students/student-pwr.gif.

The condenser water consumption in thermo-electric generation is very large: millions of gallons a day are heated up and evaporated – thus being lost to use – in a typical 1,000-megawatt nuclear power plant. In contrast, wind generation uses essentially no water, and solar utility-scale photovoltaic generation only requires a small amount of water for periodically cleaning the panels. As a result, the water requirements for electrolytic hydrogen are driven in large measure by the electricity generation method. The different water requirements for grid-, nuclear-, and renewable-driven electrolysis are explored in the following sections, and presented quantitatively in Figure IV-8.

We distinguish between water *consumption* and water *withdrawals*. Water withdrawal refers to all input water for hydrogen production. The amount of water withdrawn is the sum of water that is consumed and water that is eventually returned to the source from where it was withdrawn. Water consumption means the water is used up in the process of hydrogen production in the following ways:

- The hydrogen in the water becomes part of the hydrogen product (see the equations above).
- The portion of the water needed for electricity generation that is lost to use (by evaporation in the case of thermo-electric generation or in other ways as, for instance, when solar panels are washed down).

Other streams of water are withdrawn, but not consumed. Examples include:

- The water rejected during reverse osmosis water purification. Such purification yields a pure water stream, and a discharge stream that contains all dissolved solids that were removed from the pure water stream. Although more concentrated, the discharge stream is often clean enough to be discharged and is therefore not consumed.[91]
- The portion of the water needed for electricity generation that is not used. For example, 'once-through cooling' of power plants (see below) returns most of its withdrawn water back into the water body from where it was taken initially.

Water is also needed to produce excess steam (i.e. above the stoichiometric requirement) to drive methane reformation; it is usually subsequently recovered and reused and therefore not included in our water consumption calculations.

Water withdrawals for thermo-electric generation are larger, sometimes much larger, than water consumption, since some of the water withdrawn is not evaporated and can be re-used. Water withdrawal can be a major issue in the case of thermo-electric generation, as explained below. Even though much or most of the water withdrawn for thermo-electric generation can be re-used downstream, large withdrawals can pose constraints on production during extreme weather events, notably when the intake water temperature is high and/or when drought reduces the water available for electricity production. These factors already occasionally affect nuclear electricity generation.

We will consider three methods of water use in thermo-electric generation:

1. **Once-through cooling**: Water is taken in from a source like a river, lake, or ocean then used in the condenser, where it is heated up, followed by discharge into the same water body from which it was withdrawn. Some of the warmed water evaporates. Typically, the amount withdrawn is well over an order of magnitude larger than the amount evaporated.
2. **Cooling lake**: A large artificial lake is established and filled as the source of intake water. The water is discharged back into the lake at a different point; it circulates back around the lake to the intake, cooling down in the process – and resulting in evaporation of some of the water.
3. **Cooling tower**: The heated water from the condenser is fed by nozzles into the top of a cooling tower, cooling down as some of the water evaporates. The cooler water, collected at the bottom, can be reused a number of times before it gathers too many impurities for reuse and must be discarded. Cooling towers have the highest water consumption and the lowest water withdrawal requirements.

We consider annual averages for each of these three cooling methods when there is freshwater intake – the topic of this report.[92] Many thermal plants, including some nuclear plants, are located on coastal sites and use seawater for cooling. They have their own environmental impacts that are beyond the scope of this report; we only note here that those impacts led the California State Water Resources Control Board to adopt a policy in 2010 of ordering a stop to once-through cooling for all thermo-electric plants, including nuclear plants, by adoption of recirculating methods or by reducing impacts by alternative specified methods.[93]

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[91] Argonne 2017

[92] Withdrawals and consumption are seasonal for any given plant due to seasonal water temperature variations.

[93] California Water Resources Board 2021

i. Estimates of water consumption

Figure IV-8 shows the freshwater consumption for grey, blue, green, and the three methods of cooling nuclear power plants in case of pink hydrogen.[94] In this Figure, the bottom (blue) segment of each column expresses the amount of water that is used directly for hydrogen production. This type of water consumption entails stoichiometric water requirements, as well as process cooling water needs. An additional water use relates to the electricity that drives hydrogen production; most electricity sources require some amount of water, which is reflected by the top (red) segments of each column in Figure IV-8. These electricity needs are most important for electrolysis, which uses more electricity than other hydrogen production methods. Finally, natural gas-based hydrogen has some water requirements for obtaining natural gas.[95] These are reflected by the middle (yellow) segments for grey and blue hydrogen in Figure IV-8.

Between these options, driving electrolysis with nuclear electricity consumes the most water, because nuclear power plants are thermo-electric generation methods. A different estimate for each nuclear plant cooling method is shown. Reactors in coastal areas use seawater for cooling which is not included here. The water consumption estimates in Figure IV-8 apply only to reactors that use freshwater for cooling.

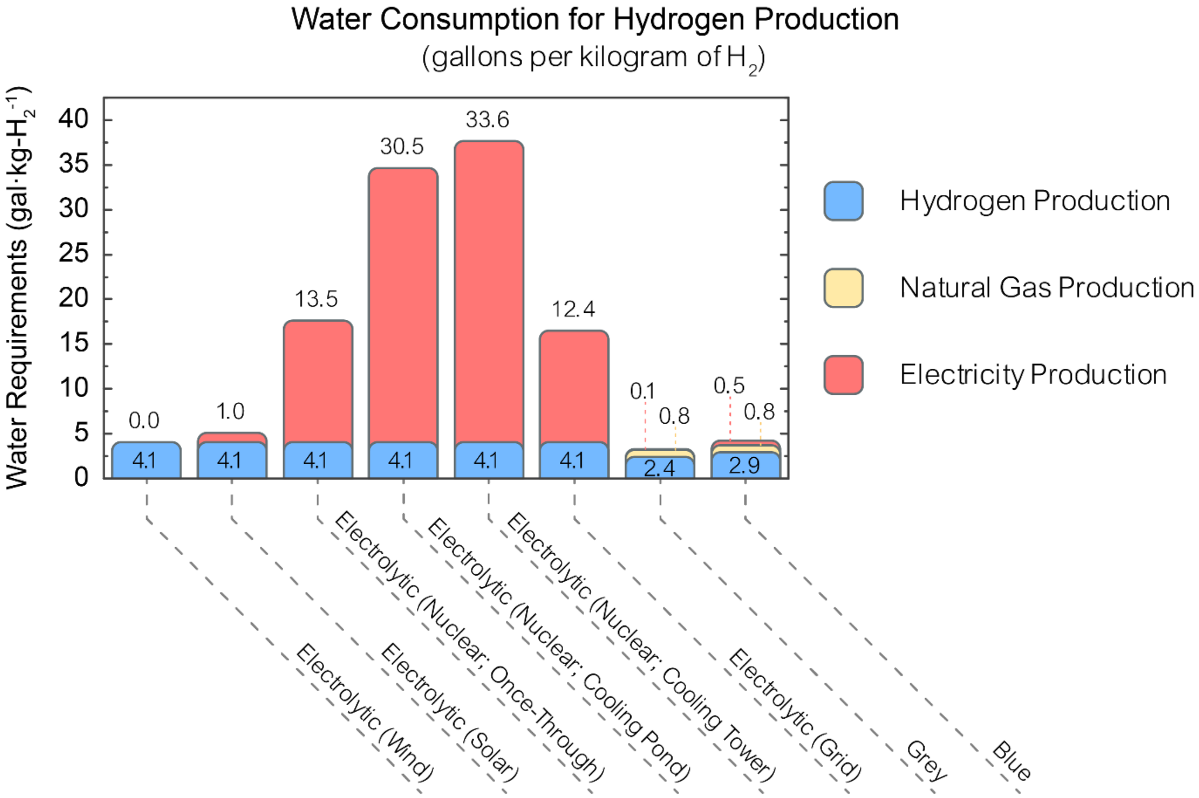

Figure IV-8: Water consumption for various methods of hydrogen production. Steam methane reforming

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[94] Argonne 2022. "Auto-thermal reforming" is a variation of steam methane reforming of natural gas with similar water requirements; it is therefore not shown separately. Several other hydrogen production methods are also analyzed in the Argonne report. We have focused here on the ones that are proposed for the widest use.

[95] Argonne 2015, Table 7.

without CCS ("grey" hydrogen) is the current dominant technology. Values rounded to the nearest tenth of a gallon. The numbers at the tops of the bars represent the water consumption for the electricity portion alone. The total water use should be read off from the axis at the left of the chart.
Note 1: Electricity-related water requirements for non-electrolytic hydrogen production methods taken as 250 gallons/MWh; this is the 2015 national average consumption over all sources of electricity production.
Note 2: Typical values for raw water required for the process have been used. Variations due to differences in raw water purity are not shown.
Note 3: Steam methane reforming requires excess steam to drive its process. The water required for this steam is assumed to be recycled and therefore not included in this figure.
Note 4: We have not considered energy requirements for liquefying natural gas since natural gas distribution in the United States is by pipeline.
Sources: Argonne 2017, Table 9 for hydrogen production values (blue bars), Argonne 2015 and EIA 2023a for natural gas water consumption, and UCS 2011 for electricity water requirements. We used 0.25 gallons per kWh for grid-supplied electricity; this is the overall national average water consumption for 2015; calculated from USGS 2019, Table 5. Only freshwater consumption is included.[96]

Likewise, grid-powered electrolysis requires large amounts of water, because most electricity is still produced using thermo-electric generation. The electricity generation part for grid-powered electrolysis can be expected to decline over time as the fraction of low-water generation methods, like solar and wind, increases. Analogously, there is considerable variation in average grid electricity water use due to the variation in thermo-electric generation across U.S. regions; the national average was used in Figure 2 for purposes of illustration only. Site-specific calculations should be done when evaluating hydrogen hub proposals.

In sum, Figure IV-8 indicates that water requirements for the electricity needed for electrolysis depend greatly on the method of generation, ranging from essentially zero for wind, to small for solar (for panel cleaning), to very large for nuclear and other thermo-electric generation: water consumption for electricity generation dominates the total in the nuclear electrolysis case. This makes "pink" hydrogen the most freshwater-intensive method among those shown in Figure IV-8.

It is also important to note that the numbers in Figure IV-8 are general estimates, which are useful for comparing different hydrogen production technologies, but unsuitable for calculating the water usage of a specific hydrogen production site. Like any analysis, the one in Figure IV-8 is sensitive to the assumptions that underlie it, a point that is also apparent from a separate analysis by the National Energy Technology Laboratory (NETL).[97] This analysis estimates the values of the blue bars in Figure IV-8 for grey and blue hydrogen to be 4.2 and 6.4 gallons per kilogram of hydrogen, respectively. This difference illustrates that the exact water requirements of hydrogen production will vary from site to site and for proposed projects must be calculated on a site-specific basis.

A final caveat is that the water input for electrolysis is somewhat affected by the efficiency of the electrolyzer, which determines how much electricity is required to make hydrogen. Figure 2 assumes an electrolyzer system efficiency of 65%, which means that 65% of input electricity is stored as chemical

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[96] Water requirements for the capital investments required for hydrogen production are not taken into account in Figure 2. While this omission means the total shown is not a complete life-cycle water consumption estimate, it is still reasonable since hydrogen would displace fossil fuel use and fossil fuel production also has water use associated with its capital investment.
[97] NETL 2022, Exhibit 5-6

energy in hydrogen.[98] If system efficiency increases to the DOE ultimate target of 77%, the electricity required for electrolysis will drop by 15.6%. The corresponding electricity-related water requirements would drop accordingly. However, hydrogen produced using nuclear or grid electricity would still be the most water intensive options.

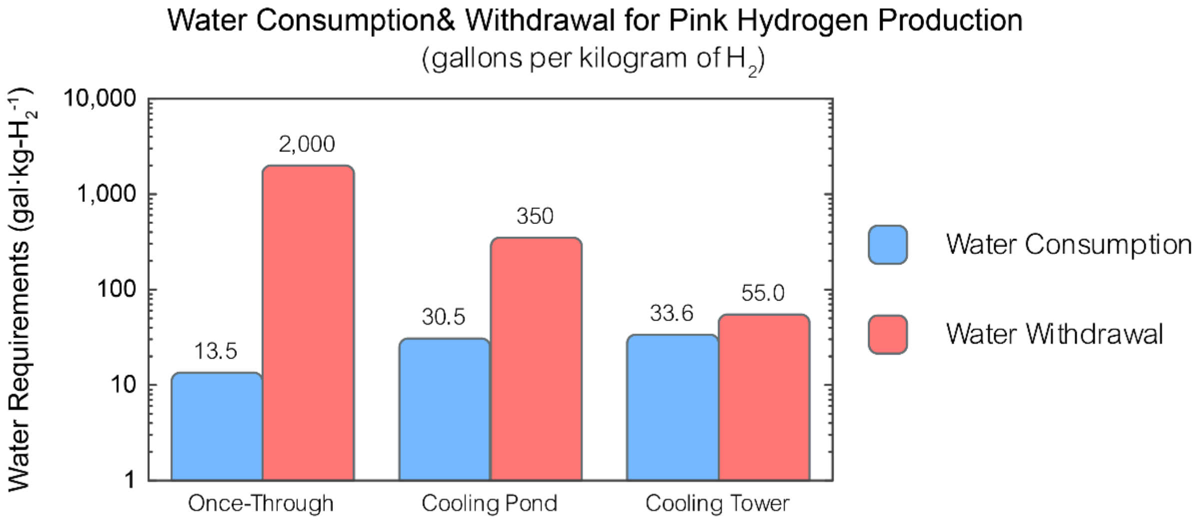
ii. Water withdrawals

The issue of withdrawal amount is important because water supply can and does become more constrained in times of very hot weather and/or drought. Thermo-electric power plants in the United States have been forced to curtail generation on occasion in such circumstances. This issue is also important because periods of very hot weather are also times of high electricity demand for air-conditioning. Electrolytic hydrogen production using thermo-electric generation such as nuclear or geothermal electricity could therefore be adversely impacted as hot weather events become more intense and frequent. This could reduce hydrogen supply reliability and increase costs. Climate change impacts on hydrogen production due to water availability are likely to vary greatly across the United States. As a result, it will be essential to factor in climate change into possible deterioration of the reliability of hydrogen supply due to water availability on a site-specific basis when siting hydrogen production facilities.

Water withdrawal requirements per kilogram of hydrogen using nuclear generation are approximately as follows:

- About 2,000 gallons *for once-through cooling*;
- About 350 gallons for *cooling ponds*;
- About 55 gallons for *cooling towers*.

Figure IV-9 compares the water consumption and water withdrawal requirements for the electricity generation portion of pink hydrogen production corresponding to the three methods of nuclear plant cooling.



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[98] DOE 2023b

Figure IV-9: Comparison of water consumption and withdrawal requirements for nuclear electricity required for pink hydrogen production by cooling method; note the logarithmic scale on the vertical axis. Process water requirements of about 8 gallons per kilogram of hydrogen not shown. Source: Calculated using USGS 2019, Table 5.

The water withdrawal requirements for grid-based electrolysis (yellow hydrogen) are similarly high: about 360 gallons per kilogram of hydrogen – similar to the cooling pond case for pink hydrogen shown above in Figure IV-9.

Figure IV-9 shows that water withdrawal outpaces water consumption but the ratio depends on the method of power plant cooling. The ratio varies from less than 2 for cooling tower cooling to about 12 for cooling ponds to about 150 for once-through cooling. This difference is not an issue when using low-water electricity generation methods, like wind and solar generation, for which water withdrawal and consumption are very low and also comparable to each other.

Figure IV-9 also highlights the differing trends for water consumption and withdrawal between cooling techniques. Notably, once-through cooling has the lowest water consumption, but requires about 6 times the water withdrawal of cooling ponds and 36 times the water withdrawal of cooling towers. But cooling towers and cooling ponds *consume* much more water mainly by evaporation: 2.5 and 2.3 times respectively relative to once-through cooling.

iii. Additional water requirements

There are also water requirements for the production of the equipment used to make hydrogen. The catalysts required for hydrogen production are important in this regard. For example, some types of electrolyzers contain rare metals like platinum and iridium. For example, a 1-MW proton electron membrane electrolysis plant requires 0.75 kilograms of iridium and 0.075 kilograms of platinum.[99] Both of these metals are predominantly mined in South Africa, where mining this quantity of metal requires 59,000 gallons of water (approximately a tenth of an Olympic swimming pool).[100] These are one-time water requirements that occur while acquiring the materials that will last years in an electrolyzer; as a result the requirements per kilogram of hydrogen are low. But the impacts in the metal-producing areas can be high (see section d of this Chapter).

Nuclear fuel water requirements also depend on the type of uranium extraction, processing, and enrichment. Overall, nuclear fuel production is water-intensive and could add several thousand gallons per metric ton of hydrogen to water requirements.[101] This would make “pink” hydrogen the most freshwater-intensive method of hydrogen production, even if seawater is used for power plant cooling.

These water impacts of uranium mining are not just direct, but also indirect, because such mining has significant environmental impacts. These impacts depend on where and how uranium is mined; currently, 95% of uranium is imported mainly from Canada (27%), Kazakhstan (25%), Uzbekistan (11%), Australia (9%) with rest being from smaller-producing countries.[102] The remaining 5% is produced domestically, predominantly through a process called ‘in-situ leaching’. This process targets low-grade

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[99] Bareiß *et al.* 2019

[100] Buchspies *et al.* 2017

[101] Argonne 2015, Table 13

[102] EIA 2023b

uranium ores by injecting an acidic or basic liquid into the ore body to dissolve uranium that is present. In most U.S. in-situ leaching mines, this liquid is an oxygenated sodium bicarbonate (baking soda) solution.[103] Once this uranium-rich liquid is pumped back up from a uranium-containing aquifer, dissolved uranium is removed and the remaining liquid is reinjected into the aquifer. In a 2012 report, the Natural Resources Defense Council identifies several key environmental impacts of in-situ leaching:[104]

- Beyond dissolving uranium, in-situ leaching also dissolves other heavy metals. When reinjected, these heavy metals degrade the quality of the mined aquifer. Unless restored, the aquifer remains contaminated.
- In-situ leaching requires large amounts of groundwater, especially during aquifer restoration attempts. For example, restoration of the Irigaray Ranch mine in Wyoming required 545 million gallons of water. This water usage is an issue, because many uranium mines are located in areas that are expected to experience medium to extreme water sustainability risks as climate change intensifies.
- In-situ leaching operations can leak both horizontally and vertically underground. These leaks can contaminate groundwater and will likely go unnoticed if monitoring wells are not installed.
- In-situ leaching creates waste, which can be toxic to wildlife.

Given these considerations, the NRDC report notes that in-situ leaching enduringly alters and degrades aquifers in which mining has taken place, especially because aquifer restoration efforts are often unsuccessful. These effects are compounded by regulatory standards that the NRDC deemed both faulty and outdated in their 2012 report. Therefore, the water impacts of uranium mining can represent a large hidden water cost for the production of pink hydrogen.

The issue of water use also applies to steam methane reforming, which uses nickel-based catalysts. The use of rarer metals, like rhodium and platinum, is also being investigated.[105] It takes about 80 gallons of water to produce one kilogram of nickel.[106] However it should be noted that the total amount of water needed for catalysts per unit of hydrogen production is smaller than the rounding error of 0.1 gallon per kilogram of hydrogen. It is the pollution impacts that are more critical (see Section d. below and Chapter VII).

Water pollution issues also arise when extracting the natural gas to make blue or grey hydrogen, because pumping natural gas can require water for hydraulic fracturing (usually shortened to “fracking”) and pollute local water sources. These impacts are felt at natural gas production sites. As a result, hydrogen production water needs are somewhat higher blue hydrogen compared to grey hydrogen. Further, blue hydrogen requires even more natural gas than grey hydrogen. As a result, all the water pollution impacts associated with natural gas production, including using fracking, would increase. Seismic impacts from reinjection of produced water would also be expected to increase. Overall, water requirements for blue hydrogen are comparable to those for green hydrogen.

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[103] NRDC 2012

[104] NRDC 2012

[105] Ruban *et al.* 2023

[106] Elshkaki *et al.* 2017

c. Total water consumption for hydrogen scenarios

We can put water use per unit of hydrogen production in perspective by estimating the total water consumption requirements hydrogen production. We use the draft Clean Hydrogen Strategy and Roadmap of the Department of Energy to illustrate the order of magnitude of water consumption involved.[107] In its "optimistic" scenario, the DOE envisions about the same level of hydrogen production in 2030 as at present (commodity hydrogen is about 10 million metric tons), but produced as green hydrogen or blue hydrogen. Hydrogen production would further increase to 20 million metric tons by 2040 and 50 million by 2050.[108] If the DOE target of $1 per kilogram for green hydrogen is achieved by 2030, production of this type of hydrogen component would be expected to rise rapidly after 2030, having the lowest warming impact and possibly also the lowest cost.

The following mix of hydrogen production methods was used to estimate the water consumption that is implied by the levels of production in the optimistic scenario in the draft DOE hydrogen strategy:

- 2020 – grey hydrogen – 10 million metric tons of H_2;
- 2030 – 90% blue hydrogen and 10% green hydrogen – 10 million metric tons of H_2;
- 2040 – 60% blue hydrogen and 40% green hydrogen – 20 million metric tons of H_2;
- 2050 Option 1: 40% blue hydrogen and 60% green hydrogen – 50 million metric tons of H_2;
- 2050 Option 2: 30% blue hydrogen, 60% green hydrogen and 10% "pink" hydrogen using freshwater-cooled nuclear-generated electricity for electrolytic production – 50 million metric tons of H_2.

The above assumptions are not an estimate or endorsement of any particular hydrogen mix; they are used here to provide an order of magnitude estimate of the water requirements in the DOE hydrogen strategy. They are illustrative calculations since neither the scale nor mix of hydrogen production methods can be forecast with any certainty. Water use for hydrogen production would rise rapidly in the DOE optimistic scenario with any mix of low-carbon production methods, mainly due to production increases but also because all three low-carbon hydrogen production methods – green, blue, pink – are more water-intensive than the present dominant method: steam methane reforming without CCS. The estimates shown in Figure IV-10 are relatively insensitive to the partition between green and blue hydrogen, since water consumption for both methods per metric ton of hydrogen is similar.

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[107] DOE Strategy 2023

[108] DOE Strategy 2023

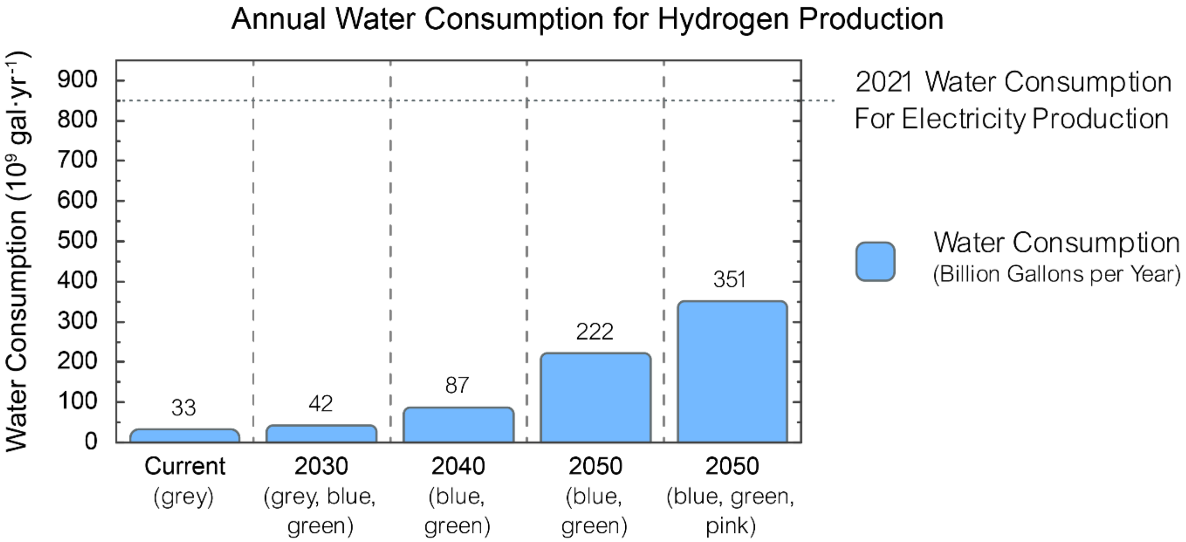

Figure IV-10: Estimates of water consumption for hydrogen production corresponding to optimistic production levels in DOE's Draft Hydrogen Strategy (DOE Strategy 2023). Based on Figure IV-8 estimates of water use per metric ton of hydrogen and USGS 2019 Table 5. Nuclear power water intensity is estimated using an unweighted average of all three nuclear cooling methods in Figure IV-9.

As Figure IV-10 indicates, water use in 2050 would be significantly larger if a substantial proportion of hydrogen were produced by nuclear-powered electrolysis: the rightmost bar in Figure IV-10 shows that if only 10% of the hydrogen production is shifted from "blue" (steam methane reforming with CCS) to "pink" (electrolysis with nuclear energy), water consumption would rise by about 30%.

Recent literature confirms the importance of taking water requirements into account. Grubert (2023) has also noted the dependance of the water-intensity of electrolytic hydrogen on the specific source of electricity used. Given that the present electricity grid is dominated by thermo-electric generation "*if the water intensity of the grid remained the same as its historical [2014] value, electrolytic hydrogen production of 15 EJ or more would require as much freshwater consumption as the entire 2014 US energy system.*"[109] 15 EJ (exajoules) is about 15% of U.S. energy use; that amount of hydrogen may displace roughly 25% of U.S. fossil fuel use, with the precise amount depending on the specific fossil fuel uses displaced and the efficiency of hydrogen use in those specific applications. Overall, the numbers presented in Figure 4 agree roughly with those estimated by Grubert (2023): approximately 400 to 500 billion gallons per year for two scenarios producing approximately 50 million metric tons of hydrogen per year.[110]

Considerations relating to net water consumption, taking into account the reduction in water use due to lower fossil fuel use, are more complex; we discuss them briefly here. Figure IV-10 compares water consumption corresponding to the DOE draft hydrogen strategy with the water consumption by the United States electricity sector in 2021. Electricity generation consumes more water than any other

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[109] Grubert 2023

[110] The paper assumes an electrolyzer efficiency of 75%. Its 'Williams Low Demand' scenario estimates 450 billion gallons per year to produce 44 million metric tons of hydrogen per year, while its 'Williams Central' scenario estimates 530 billion gallons per year for 57 million metric tons of hydrogen per year. The water intensity of the electricity grid differs slightly for each scenario.

industry in the United States, other than agriculture.[111,112] The comparison with electricity-based water demand explicitly shown as a percentage number in Figure IV-11. Fifty million metric tons of hydrogen production would require roughly seven to ten times water the consumption for present-day hydrogen production. It would raise freshwater use to roughly 200 billion to 400 billion gallons a year (rounded) – which would be between about 25% and 40% (rounded) of the 2021 water consumption in the electricity sector.

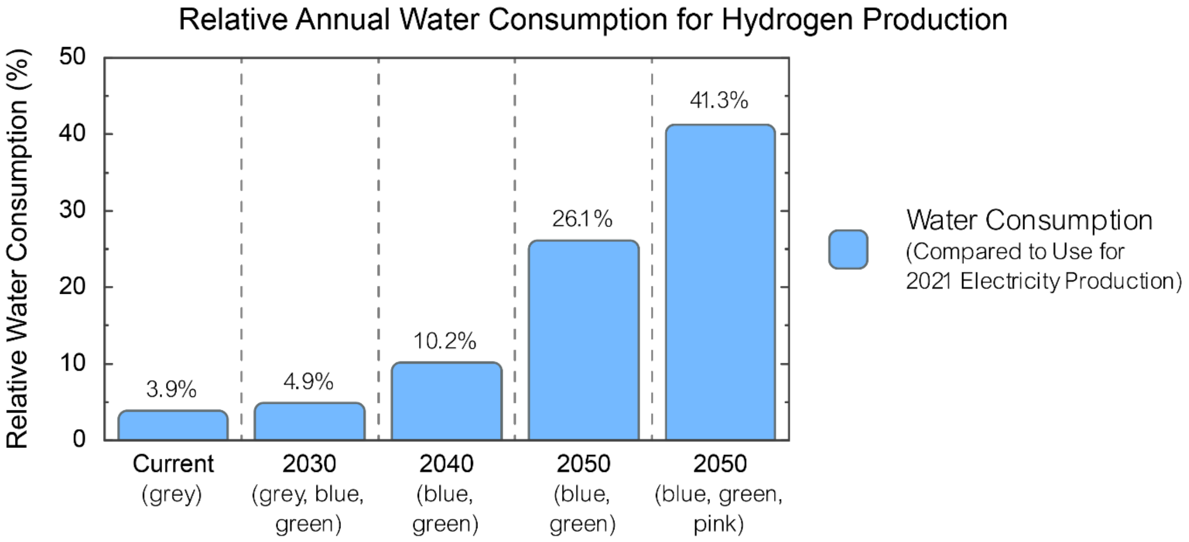

Figure IV-11: Hydrogen production water consumption as a percentage of 2021 electricity sector water consumption. Source: Data in Figure IV-10.

The DOE also has a base case in which hydrogen demand by 2050 would be roughly half of the optimistic 2050 level. As a result, the range of potential water consumption for hydrogen production would be 110 to 350 billion gallons per year in 2050, depending mainly on total hydrogen demand but also on how much of the hydrogen is produced using nuclear electricity.[113]

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[111] USGS 2018

[112] Water consumption in the electricity sector in 2021 was about 850 billion gallons. USGS 2019, Table 5. This publication provides the 2015 water consumption estimates. We calculated the approximate 2021 water consumption requirements by factoring in the changes in electricity generation between 2015 and 2021. Electricity generation data are from the Energy Information Administration at https://www.eia.gov/energyexplained//electricity/charts/generation-major-source.csv Electricity sector fresh water withdrawals in 2015 were 80 billion gallons a day (USGS 2019, Table 5), compared to 118 billion gallons a day for irrigation (USGS 2018 p. 1). However, only about 3.4% of thermo-electric generation freshwater withdrawal is actually consumed by evaporation. (Note: USGS 2018 has a somewhat higher freshwater withdrawal for electricity generation (96 billion gallons a day) than USGS 2019, which we have used in this report.

[113] We should note that only hydrogen from new nuclear reactors with capacity dedicated to that end would result in net greenhouse gas emission reductions. Diverting existing nuclear electricity for hydrogen production – as is being done with DOE support at the Nine Mile Point nuclear plant in New York State – would generally have significantly increased net emissions even though the onsite emissions would be zero. The nuclear electricity for hydrogen would be diverted from existing loads – which then would have to be supplied from the electricity grid resulting in associated carbon emissions. We estimate that in the case of the Nine Mile Point pilot plant the global emissions per kilogram of hydrogen would be greater than those associated with grey hydrogen.

Our own estimate of hydrogen use in Chapter VI that would provide a clear climate benefit by 2050 – roughly 30 million metric tons (rounded) – is towards the lower end of the DOE range. This would entail using about 140 billion gallons a year of water for making green hydrogen from renewable energy that would otherwise be curtailed. These are indicative numbers from a climate perspective and do not take siting and water justice issues into account. They should not be seen as a recommendation, but rather as an illustration for comparison with the draft DOE hydrogen strategy. Moreover, the portion of hydrogen production process water used in stationary applications could be recovered. This would be the case, for example, in fuel cell peaking generation and combined heat and power in industry – but not if the hydrogen is burned (which we do not recommend). Thus, the net water requirements for green hydrogen in the mix of applications we recommend could be lower than 140 billion gallons per year – especially since we do not recommend use in buildings and only minor use, if necessary, for long-distance trucking transport relative to DOE's optimistic case.

Figure IV-11 also shows the evolution of water consumption for DOE's optimistic hydrogen production scenario as a percentage of the 2021 water consumption in the electricity sector. Forty percent of 2021 electricity generation water consumption may well make hydrogen production the dominant water user sometime between 2030 and 2050, except for agriculture. This is because water consumption in the electricity sector, which has already been declining, will decline rapidly as the fraction of solar and wind generation increases: utility-scale solar generation consumes only about 5% of the water consumed by coal-fired generation per unit of power production, while wind-generated electricity requires essentially none.

Freshwater consumption for hydrogen could be reduced in a variety of ways. For instance, purified sanitary wastewater that may be unacceptable for residential uses for social reasons could, if it met the purity criteria, be used for hydrogen production.[114,115] However, unless non-potable water of adequate quality is already available, water purification would add to the expense of hydrogen production. The type of input water would also determine electricity usage and pollution issues associated with hydrogen production, which in turn affects environmental justice burdens and public health impacts.[116] Alternatively, the direct use of seawater – that is, without desalination – for electrolysis would reduce freshwater requirements to a small amount. However, this is a nascent technology that is currently far from commercial.

Mining geologic aquifers of brackish water or using oil and gas-related produced water and purifying it for hydrogen production has also been proposed where fresh water is scarce.[117] Specifically, it has been proposed to examine this possibility for New Mexico.[118] There are a large number of technical, ecological, and environmental justice considerations associated with such an approach including the priorities for water use where it is already scarce.

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[114] LA City Council 2022

[115] Water purity standards for electrolysis are higher than those for residential water supply.

[116] These potential impacts would likely be much lower than the impacts of fossil-based technologies that would be replaced by hydrogen. This consideration is further explored in section V.

[117] Fairley 2023

[118] New Mexico Consortium, no date.

Finally, distributed hydrogen production facilities may be appropriate for instance to support community microgrids to strengthen resilience of electricity supply and ensure continuity of supply to essential loads during multi-day grid outages.[119]

d. Mining and material processing impacts

Energy systems generally involve intensive use of materials, many of which involve energy-intensive mining, processing, and fabrication. Hydrogen is no exception. The main energy inputs envisioned for hydrogen production are natural gas or electricity. Steel and cement are also used in large quantities. Likewise, producing hydrogen can require rare materials for catalysts, and in the case of nuclear energy, the fuel for electricity production. Mining these rare metals involves moving large amounts of earth, which drastically alters the earth's surface and can endanger the environment for long periods that can extend to thousands of years. Thus, producing, transporting and using hydrogen can have many impacts relating to the materials requirements of a hydrogen economy.

This section is a short exploration of some of the materials issues that could have significant environmental impacts. Most of these impacts will not occur at the points of hydrogen production or use or in the transportation and storage steps. Rather, they occur in the countries and regions where the energy production and electrolyzer materials are mined and processed. As illustrated below, the countries are often in the Global South; when they are in the Global North, the impacts are often on Indigenous lands. For instance, electrolysis is the most promising hydrogen production method for reducing greenhouse gas emissions. Yet, electrolyzers contain metals such as nickel, platinum or iridium as catalysts.

Mining these rare elements involves moving huge quantities of earth. In surface mining, large amounts of overburden – the soil above the main ore body – has to be removed. Low-grade ores are left scattered on site. Subsequent processing of ores with relatively dilute amounts of target elements is generally a chemical- and water-intensive process, since large amounts of acids or bases are used to concentrate and purify the ores. The processes leave behind almost all the unusable 'waste' materials in the ore as mill tailings. These tailings generally contain toxic chemicals (acids or bases, for instance), heavy metals, and often radioactive materials like uranium and thorium. For instance, the U.S. Environmental Protection Agency notes that: "Rare earth minerals are processed primarily from ores and minerals that naturally contain uranium and thorium."[120] In turn, uranium and thorium sit at the top of decay chains that contain other radioactive materials. For instance, uranium-238 decay products include thorium-230, radium-226, and radon-222, all of which are radioactive.

These issues will be explored here for the platinum and iridium that are used in proton-exchange membrane electrolyzers, and the nickel that is used in alkaline and anion-exchange membrane electrolyzers. These materials are also used in some types of fuel cells, as described in Chapter VI.

A 1-MW proton electron membrane electrolysis plant requires 0.75 kilograms of iridium and 0.075 kilograms of platinum.[121] Both of these metals are predominantly mined in South Africa, where mining this quantity of metal requires 224,000 liters of water (approximately a tenth of an Olympic swimming

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[119] IEER is exploring community microgrids and long-duration energy storage and preparing a report on that topic for Just Solutions Collective. See Makhijani *et al.* 2024

[120] EPA 2023a

[121] Bareiß *et al.* 2019

pool).[122] This water usage creates conflicts between frontline platinum communities and mining companies, to the extent that *"platinum belt communities are at risk of becoming green sacrifice zones to satisfy the climate ambitions of Global North countries."*[123] This water use for platinum and iridium mining are associated with high environmental and social risks.[124] These risks will likely decrease in a relative sense as next-generation electrolyzers require less platinum and iridium per amount of hydrogen output,[125] but will increase in an absolute sense as the demand for these metals increases.[126]

Different but equally important issues arise when mining nickel for use in alkaline and anion-exchange membrane electrolyzers. Most of this nickel is mined in Indonesia, which holds the world's largest nickel reserves.[127] It currently meets 30% of global nickel demand, and is projected to account for the majority of global nickel production growth between 2021 and 2025.[128] Nickel has recently gained prominence for its use in electric vehicle batteries, and its mining has had significant social and environmental effects in Indonesia. For example, 'red soil' waste from mine excavation and coal plant wastewater have entered waters near the village of Kurisa, thus reducing local fish populations and forcing fishers to fish further away at sea.[129] These reduced fishing yields and expensive trips to unpolluted sea areas have reduced fishermen's incomes. Likewise, local mine workers are left exploited by their employer,[130] and according to local workers: "deaths and injuries are common."[131]

i. Supply chain risks

Hydrogen-producing electrolyzers, including those producing green or pink hydrogen, contain a variety of metals that depends on the type of electrolyzer. Some of these metals are scarce or concentrated in single geographic areas. These constraints can leave a material's supply vulnerable to physical supply chain interruptions, market imbalances and governmental interventions. Such risks could drive up material prices or physical shortages of particular metals.[132] A brief overview to the vulnerability towards these risks will be given here for each electrolyzer type.

For alkaline electrolyzers, the important metals are the nickel and iron that are used in the cathode, anode and gas diffusion layer, as well as the zirconium contained within the electrolyzer diaphragm.[133] As mentioned above, nickel is increasingly important as an electric vehicle component. Although the global nickel supply chain is currently not a limiting factor,[134] some studies project nickel demand to grow by 2 to 4 times in 2050.[135] Nickel demand might therefore be constrained in the future, if expansion of its various uses follows current projections.[136] Not all materials are likely to be supply-

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[122] Buchspies *et al.* 2017
[123] Matsabu 2022
[124] Lèbre *et al.* 2020
[125] Bareiß *et al.* 2019
[126] Schlichenmaier *et al.* 2022
[127] Rushdi *et al.* 2021
[128] IEA 2021
[129] McCarthy 2011
[130] Rushdi *et al.* 2021
[131] Yeung 2023
[132] Erdmann and Graedel 2011
[133] Shiva Kumar and Lim 2022
[134] Watari *et al.* 2019
[135] Watari *et al.* 2020
[136] Schlichenmaier *et al.* 2022

constrained, though their mining and processing will, in all cases, have significant environmental impacts. Iron falls in this category; zirconium may also be in it.[137]

These material demands are similar for anion-exchange membrane electrolyzers, which predominantly contain nickel, iron and cobalt as catalysts, as well as nickel gas diffusion layers.[138] Not all AEM electrolyzers contain cobalt, which has been increasingly mined for use in batteries and currently faces medium supply constraints.[139] Cobalt demand is projected to outpace current supplies by 3 to 8 times by 2050;[140] however, this demand could be met if increases in cobalt mining rates keep up with historic growth.[141] Although supply might therefore not be a showstopper, it is important to note that around 70% of the global cobalt supply comes from the Democratic Republic of Congo,[142] where it is associated with extensive child labor and dangerous conditions for miners.[143]

Different constraints arise for proton-exchange membrane electrolyzers, which rely on platinum and iridium catalysts, titanium gas diffusion layers, as well as so-called bipolar plates that are made of titanium and sometimes coated in gold or platinum[144]. Platinum is a rare metal, and its production is highly geographically concentrated: an estimated 70% to 77% of platinum is mined in South Africa[145] Platinum availability is currently constrained,[146] and historic and projected mining rates are unlikely to keep up with global demand.[147] Similar concerns arise for iridium, which is a byproduct of platinum mining and therefore predominantly comes from South Africa, which provides 85% of the global supply.[148]

Iridium demand is likely to increase in the short term as proton-exchange membrane electrolyzers are upscaled, but long-term demand per unit of capacity will likely be lower as electrolyzers are optimized to require less iridium.[149] Even so, demand might be high enough to outpace supply by 2050.[150] Gold faces similar present-day and future supply pressures,[151] but electrolyzers tend to contain less gold than platinum or iridium. Finally, titanium is not supply-constrained because it is relatively abundant.[152] Although some studies indicate a need for increased mining,[153] other publications do not project constraints for PEM electrolyzer rollout due to expected technology improvements that would reduce the amount of required titanium per electrolyzer.[154]

The fourth electrolyzer type is the solid oxide variety, which uses nickel-based cathode catalysts and gas diffusion layers, yttria-stabilized zirconia as the solid oxide, and cobalt-coated stainless steel as the

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[137] Watari *et al.* 2021
[138] Shiva Kumar and Lim 2022
[139] Watari *et al.* 2019 and Schlichenmaier *et al.* 2022
[140] Watari *et al.* 2020
[141] TNO 2019
[142] IEA 2021
[143] Shiva Kumar and Lim 2022 and IEA 2021
[144] Shiva Kumar and Lim 2022
[145] TNO 2019 and Kiemel *et al.* 2021
[146] Watari *et al.* 2019 and Watari *et al.* 2020
[147] Schlichenmaier *et al.* 2022 and TNO 2019
[148] TNO 2019
[149] Terlouw *et al.* 2022
[150] Schlichenmaier *et al.* 2022
[151] Watari *et al.* 2019 and TNO 2019
[152] Watari *et al.* 2019
[153] TNO 2019
[154] Kiemel *et al.* 2021 and Terlouw *et al.* 2022

bipolar plate.[155] The anode catalyst is typically an oxide composed of a mix of either lanthanum, strontium, cobalt and iron, or of lanthanum, strontium and manganese. Lanthanum and strontium supply constraints are currently low to medium,[156] and long-term lanthanum constraints are not expected.[157] No current or future limitations are expected for manganese.[158] Yttrium faces low to medium constraints;[159] despite that, it is considered a critical mineral because its ores are geographically concentrated and it is difficult to recycle.[160]

In short, each electrolyzer type involves different material availability concerns, but such concerns are likely less relevant for alkaline, anion-exchange membrane than for proton-exchange membrane (because of platinum and iridium requirements) and solid oxide electrolyzers (because of yttrium requirements). It is important to note that these assessments are based on projections that vary in geographical scope, evaluated end uses and assumed material intensity for these end uses. Actual material demand could therefore increase if unexpected uses arise, or decrease if technological improvements or societal changes reduce how much material is needed for each use. For instance, much more intensive investments in energy efficiency could reduce electricity demand, including for hydrogen, well below projections. While beyond the scope of the present report, we note that significant reduction in environmental justice impacts is possible relative to present estimates if an overall design of the energy transition is more centered on efficiency, affordability, and community needs.[161]

As we noted regarding water use, the displacement of fossil fuels by hydrogen, mineral requirements and associated processing will also decline since fossil fuels involve extensive mining, processing, and transportation related investments. The net global impact will therefore be less than that obtained by considering the impacts of hydrogen alone. In fact, the energy transition may require less mining overall than the current fossil-based energy system.[162] Still, mining activities might shift from one region to another, such that overall net changes in mining impacts do not negate site-specific environmental and supply-chain considerations.

Growing hydrogen production will require an increasing stock of materials used in the production process – including the catalysts. But as the industry matures and something close to a steady state is achieved, most of the materials could be recovered, reprocessed and reused. The U.S. steel industry is a good example – over 80% of the steel made in the United States is recycled material.

As discussed above and in Chapter VII, mining and processing of materials like iridium, platinum, and nickel often has severe adverse impacts on communities in the Global South and on Indigenous communities (among others) in the Global North. Similar, though generally less severe, impacts can occur during recovery and recycling of metals: an essential process in a future, more circular economy. For example, metal recovery often employs acids and organic solvents to recover metals. Using such liquids is subject to regulations, but liquid waste streams can still pollute water resources. For example, waste can be released inadvertently: in 2022, the City of Austin (TX) reported that Samsung's Austin

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[155] Shiva Kumar and Lim 2022
[156] Watari *et al.* 2019
[157] Schlichenmaier *et al.* 2022
[158] Watari *et al.* 2019, TNO 2019 and Watari *et al.* 2021
[159] Watari *et al.* 2019 and Schlichenmaier *et al.* 2022
[160] Kiemel *et al.* 2021
[161] Riofrancos *et al.* 2023
[162] Nijnens *et al.* 2023

Semiconductor facility discharged up to 763,000 gallons of sulfuric acid waste into a local creek over the course of 106 days.[163] Importantly, environmental exposure is not the only risk to local communities, because metals recycling also poses occupational hazards to recycling workers. These workers can accidentally be exposed to hazardous liquids and, during disassembly of recycled equipment, to airborne dust. Excessive inhalation of such dust can cause a group of lung conditions known as pneumoconiosis.[164]

These examples are not exhaustive, but merely an example of the many historic, ongoing and future occupational and environmental justice risks that are paired with industry. Thus, while recycling of materials is critical to progressing towards a circular economy, stringent protections are needed to ensure that recycling does not increase the impacts burdens on already overburdened communities. To this end, siting, strong regulations and vigorous enforcement will all be needed.

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[163] City of Austin 2022

[164] Cullinan and Reid 2013

V. Storage and Transportation

a. Storage

Hydrogen generally is not used immediately after production. Storage is therefore generally necessary. A variety of storage options is available, for specific requirements; each has its own benefits and drawbacks. The most commonly considered options for hydrogen storage are:

1. Compressed hydrogen storage in cylinders or tanks.
2. Liquid hydrogen storage.
3. Compressed hydrogen storage in large reservoirs underground.
4. Ammonia as a hydrogen energy carrier transportation for reconversion to hydrogen at the point to use.

The common feature of all these options is that for a given energy storage requirement, the volume of hydrogen needs to be reduced, since the volumetric energy density of hydrogen is very low. The different methods of increasing volumetric energy density depend on the length time for which storage is needed and the amount of hydrogen to be stored.

Here, we distinguish between smaller capacities (below 150 kilograms, equivalent to about 5 MWh of energy) on the one hand and large capacities (over 300 metric tons, about 10,000 MWh of energy) on the other.[165,] This scale distinction is typically paired with a time distinction between shorter (days to weeks) and longer time scales (weeks to seasons). Smaller scale storage, practiced for over a century, is suitable for applications such as fueling vehicles or distributed fuel cell generation. Larger-scale, longer-duration storage would be needed to support utility-scale generation or steel production if the hydrogen is not produced onsite or delivered by dedicated pipelines.

At smaller capacities, hydrogen can be stored in vessels like cylinders or tanks. This densification is typically done by either compressing hydrogen gas or cooling it below its boiling temperature (-253 °C; -423 °F) to liquefy it.[166]

Compressed hydrogen storage occurs at pressures between 200 and 700 bar.[167] (For reference, atmospheric pressure is approximately 1 bar.) Because the cylinders must be able to withstand such high pressures, they are made of steel, carbon fiber or a combination of both. If steel is used, the interior is lined with a polymer to prevent hydrogen embrittlement of the steel.[168] Cylinders are categorized Type 1 through Type 4, depending on whether they are fully made of steel, a carbon fiber-reinforced steel (Type 2 and 3), or carbon fiber (Type 4). Incorporating carbon fiber tends to increase the cost of a cylinder, but reduces weight by requiring less steel.[169] Type 3 and 4 cylinders can also withstand higher pressures, such that these expensive vessels store the most hydrogen per unit of cylinder mass and volume. Compressed hydrogen storage has two significant advantages: it can be kept at room temperature and the cylinders can be filled/emptied at a wide variety of gas flow rates.

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[165] Elberry *et al.* 2021 and IEA 2019

[166] Rivard *et al.* 2019

[167] Rivard *et al.* 2019. 1 bar equal pressure of approximately 1 atmosphere, which is 14.7 pounds per square inch at sea level.

[168] Embrittlement renders the cylinders vulnerable to cracking; it occurs when hydrogen molecules permeate metals like iron and nickel to form hydrides. It is also called stress-induced cracking.

[169] Rivard *et al.* 2019.

However, the high pressures associated with compressed storage involve safety issues, requiring careful handling of the cylinders. Most notably, rupture of cylinders can cause them to explode; accidental explosions can result in fires.

Greater quantities of hydrogen can be stored in a given volume by liquefying it. This involves cooling it to extremely low temperatures.[170] Although liquefied hydrogen is subsequently stored in well-insulated containers, some amount of ambient heat is constantly absorbed by the container and the hydrogen it contains. This heat causes some hydrogen to boil, raising the pressure in the storage tank. To keep this pressure increase from exploding the storage tank, hydrogen is periodically vented through a relief valve. Vented hydrogen is often referred to as 'boil-off'. The hydrogen that boils off can be captured, but if it is not, this phenomenon can cause substantial losses: 0.1% to 3% every three days.[171] Hydrogen loss adds to the cost of hydrogen, since the loss must be replaced. It also diminishes hydrogen's climate benefits due to its indirect warming impact (see Chapter III). Liquefied hydrogen also suffers from high cost and low energy efficiencies due to the need of extensive cooling equipment.[172] Furthermore, using liquefied hydrogen is more hazardous than using compressed hydrogen for several reasons: liquid hydrogen is dense enough to form a ground-level blanket if spilled, hydrogen must be vented away from ignition sources, and safety vents can be clogged by ice formed by the low storage temperatures.[173] Additionally, hydrogen can be contaminated by condensed air that forms on the equipment, thus forming a highly flammable mixture. But liquified hydrogen does have one big advantage: volumetric energy density. More than four times the amount of hydrogen energy can be stored in a given volume as liquid compared to storage as a gas at 200 bar. This advantage mostly disappears if the pressure of gaseous hydrogen is raised to 700 bar, at which pressure liquid hydrogen is only about 20% more energy-dense per unit volume.

A variety of other hydrogen storage methods is currently being researched, but compressed and liquefied hydrogen are currently the best established ones.[174] Between these, compressed hydrogen is the industry standard for most applications due to its high energy efficiency and convenience.[175]

Though widely used for smaller-scale storage, the capacity of cylinder-stored and liquefied hydrogen is insufficient to meet the large-scale storage requirements that would accompany the seasonal storage of hydrogen made when excess renewable energy – electricity above the grid requirements at a specific time – is available. Since demand and supply must be balanced at all times, this excess electricity must either be curtailed or stored in some way.

Even now, states with high renewable energy penetration have significant energy surpluses. For example, California's deployment of renewable energy outpaces its capacity to store excess electricity: California's electricity grid operator (CAISO) expanded its battery capacity from approximately 9,400 MWh in 2021 to 16,100 MWh in 2022,[176] while simultaneously increasing the curtailment of electricity production from 1.5 million MWh in 2021 to 2.4 million MWh in 2022.[177] Storing this electricity in

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[170] The lowest temperature to which anything can be cooled is -273.15 ^{o}C (-459.67 ^{o}F). The temperature at which hydrogen gas becomes a liquid is most of the way down to absolute zero (-253 ^{o}C; -423 ^{o}F)

[171] Ni 2006

[172] Ni 2006 and Rivard *et al.* 2019

[173] Ni 2006

[174] Rivard *et al.* 2019

[175] Ni 2006 and Rivard *et al.* 2019

[176] CAISO 2023a

[177] Okoroafor *et al.* 2022a and CAISO 2023b

batteries at current prices is far too expensive for the large electricity surpluses expected in the spring and fall, at a future point in time when there is a high penetration of wind and solar. Optimistically, even the low-cost long-duration, 100-hour, iron-air batteries now in development are projected to cost ~$20 per kWh, ten times cheaper than the common lithium-ion batteries.[178] Yet seasonal surpluses at high wind and solar penetration could run into hundreds of billions of kWh, making the investment required for battery storage extremely large. Shifting loads to the times when surplus renewable energy is available from times of deficit – one form of demand response – can significantly reduce the need for battery capacity. But this requires appropriate price signals, demand response aggregation, and suitable grid operators dispatch protocols.[179]

To make as complete a use of solar and wind resources as possible, storage technologies that are longer duration than a few days are necessary. This is in large measure because significant portions of the surpluses of supply that would have to be curtailed occur in the spring and autumn, during which demand is generally much lower than in the summer or winter. Several approaches are possible – including pumped hydropower, compressed air storage, seasonal thermal storage, and hydrogen. Of these, hydrogen has the advantage of being a very flexible energy carrier that can be transported from the point of production to the point of long duration energy storage and from there to the point of use. Of course, two or even all three facilities could be in the same location, but they do not have to be.

When using hydrogen to store excess electricity, California's curtailed 1.5 billion kWh of electricity could be used to produce 34,000 metric tons of hydrogen, assuming an electrolyzer with 75% efficiency. At current industry standards, storing this much hydrogen would take 820,000 cubic meters (29 million cubic feet), which corresponds to 17 million 'G-size' gas cylinders.[180] Such amounts of hydrogen could be stored at a large scale, on monthly to seasonal time scales, though typical storage times might be much shorter.[181] Storing hydrogen on such a scale in cylinders would be highly impractical. Liquid hydrogen, with its boil-off issues, is similarly impractical. Storing such large amounts of hydrogen would therefore take a different type of solution.

At these scales of storage, underground hydrogen storage (UHS) is an option that could play a significant role in some important sectors as part of decarbonizing the energy system. As the name suggests, this type of technology involves pumping hydrogen into rock layers below the earth's surface for storage and retrieving it at a later time when there is a need for hydrogen. Although a more novel approach for hydrogen, such subterranean storage has been used to store natural gas since 1915.[182]

Broadly speaking, there are three main requirements to store any type of gas underground (Figure V-1):[183]

1. The presence of a porous or hollow space.
2. A cap rock above the hollow space that is impermeable to gas. The leak-proofness of a cap rock or gas storage reservoir is often referred to as 'tightness'.

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[178] Agatie 2023

[179] Makhijani *et al.* 2024

[180] Elberry *et al.* 2021

[181] For examples of this type of storage in different scenarios, see Figure 13 of Le *et al.* 2023, Figure 12 and 13 of Lubello *et al.* 2022, and Figure 7 and 8 of Mayyas *et al.* 2020.

[182] Zivar *et al.* 2021

[183] Heinemann *et al.* 2021

3. A trap shape, such as a dome, that keeps stored gas underneath the cap rock and prevents it from leaking out.

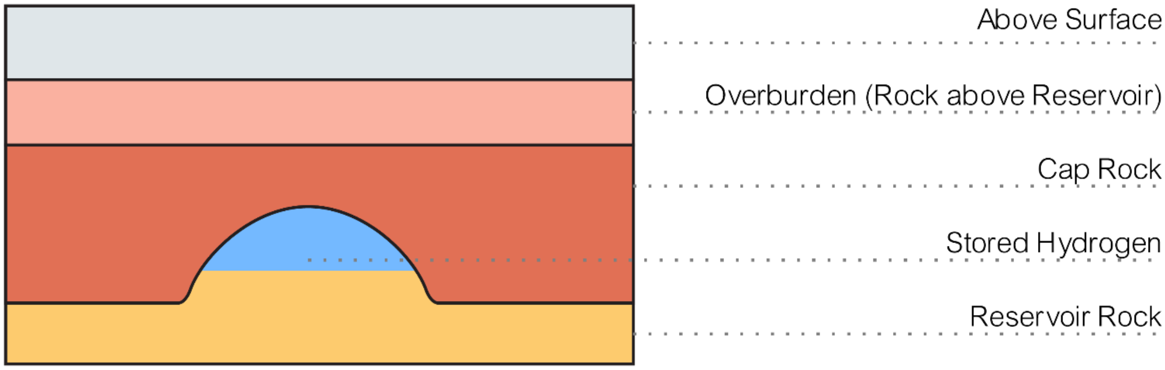

Figure V-1: Schematic depiction of an underground gas storage reservoir.

Cavities such as the one in Figure V-1 can be filled with gas through a drilling well. When doing so, one should bear in mind that each underground cavity has a maximum safe operating pressure, as well as a minimum pressure below which it is difficult to pump stored gas out of the reservoir. These considerations define different types of gas being stored: working gas and cushion gas.[184] Working gas is the amount of gas that can readily be injected and removed from a reservoir, whereas cushion gas is a fixed amount of gas that remains in the reservoir to maintain the minimum operating pressure. These working and cushion gases can be the same gas (such as hydrogen), but they do not have to be (such as having a hydrogen working gas and nitrogen or carbon dioxide cushion gas).[185]

There are various types of reservoirs that can be filled with the aforementioned gases and meet the geological requirements depicted in Figure V-1. These types can broadly be divided into two types:[186]

1. <u>Porous.</u> These types of reservoirs contain porous rocks, which have narrow but extensive networks of holes in them that can accommodate gas. Such reservoirs include depleted natural gas fields and aquifers.
2. <u>Cavity.</u> These types of reservoirs are large hollow caverns, which are often human-made. Such reservoirs include salt and rock caverns.

Each of these storage spaces is briefly described below.

Depleted natural gas fields are the most commonly used reservoirs for storing gas underground: approximately three-fourths of natural gas is currently stored in such fields.[187] Using depleted gas fields for hydrogen storage is convenient from a geological perspective, because they are guaranteed to meet the criteria outlined in Figure V-1. After all, they have already trapped the natural gas that was there and was subsequently produced.[188] In addition, these depleted fields often have gas transportation infrastructure in place.

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[184] Crotogino 2022
[185] Okoroafor *et al.* 2022b
[186] Zivar *et al.* 2021
[187] IEA 2022 and Tarkowski 2019
[188] Crotogino 2022

However, injecting hydrogen into these reservoirs is more difficult than injecting natural gas, because hydrogen is more diffusive, less viscous and more reactive.[189] Another challenge is the presence of residual natural gas in depleted fields, because such fields are hardly truly empty. This residual gas can mix into the stored hydrogen, thus contaminating it and rendering it unusable for some types of fuel cells. In addition, 45% to 60% of the reservoir volume is taken up by cushion gas, which must be left there, as noted above.[190] Furthermore, porous reservoirs can host hydrogen-consuming microbes,[191] and reactive minerals. Both of these can react with hydrogen, which consumes the hydrogen and can produce methane and hydrogen sulfide that contaminates the remaining stored gas.[192]

The second type of porous storage site is the aquifer, which is a porous water-containing rock formation. Currently, 11% to 13% of global underground natural gas storage occurs in aquifers. These reservoirs are similar in many ways to depleted gas fields, except that the presence of a cap rock or trap structure is not guaranteed.[193] Consequently, extra exploration efforts need to be made to ensure that an aquifer meets all of the criteria in Figure V-1, which increases the cost and time requirements to store hydrogen in aquifers. Aquifers do not contain any residual gas that could contaminate stored hydrogen, but all other drawbacks of using depleted gas fields apply to aquifers as well. These include hydrogen reacting with microbes and minerals. The cushion gas requirement of aquifers is slightly higher than for depleted gas fields: 50% to 70% of stored gas is trapped as cushion gas.[194] Such a high cushion gas requirement imposes an investment cost, since the cushion gas hydrogen must be purchased initially, piped into the field, and then left there.

Using aquifers and depleted natural gas fields comes with three other drawbacks: induced seismicity, low maturity, and uncertain economics. Induced seismicity refers to earthquakes and tremors that are caused by underground human activities such as drilling for gas or geothermal wells. In the context of hydrogen storage, seismicity can be caused when hydrogen reacts with load-bearing rocks, which possibly weakens them.[195] Alternatively, clay-bearing areas can swell in the presence of hydrogen, which can cause earthquakes or tremors.[196] The second issue, maturity, refers to hydrogen storage in porous reservoirs being relatively unproven: these reservoirs are not widely in use for hydrogen storage.[197] Such low maturity feeds into the uncertain economics of storage in porous rocks, which means that the overall costs and economic benefits of this type of hydrogen storage are currently difficult to estimate.[198] More research is therefore necessary before using these geological features to store hydrogen.[199]

Underground storage in salt caverns is a more workable approach. Such caverns are large human-made spaces constructed in salt deposits. Salt caverns are commonly used for underground natural gas

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[189] IEA 2022

[190] IEA 2022

[191] As discussed in Chapter III, microbes in the soil are one of the main ways hydrogen is removed from the atmosphere.

[192] IEA 2019

[193] Crotogino 2022

[194] IEA 2022

[195] Heinemann *et al.* 2021

[196] Heinemann *et al.* 2021

[197] IEA 2019

[198] Hydrogen TCP-Task 42 2023

[199] Hydrogen TCP-Task 42 2023

storage; they have been also used for hydrogen storage since 1972.[200] They are created through a process called ‘solution mining’. This method uses water to dissolve salt, creating the salt cavern and a highly concentrated brine stream that needs to be disposed of as waste. Solution mining creates a gas-tight cavern,[201] in which only 25% to 35% of the stored gas is needed as cushion gas,[202] correspondingly reducing the initial cost of setting up the storage system. The decades of experience make this a more mature option than other types of sites for underground storage. However, suitable salt deposits to create caverns are not available everywhere.[203] Furthermore, finding a water source for solution mining can be an issue, as is the problem of responsibly disposing of the brine that mining creates.[204] Some of this brine tends to remain in the salt cavern, where it can host bacteria that consume hydrogen. Even so, hydrogen is being stored in salt caverns in Britain, Germany, and the United States.[205]

These drawbacks might be mitigated by using rock caverns, which is a more experimental underground gas storage method. Although such caverns have been used to store liquids like propane, butane and crude oil,[206] their tightness for storing gases is far from proven.[207] They need to be modified by installing a ‘liner’, which keeps the gas inside. Rock caverns are currently being tested at smaller scales; a notable example is the HYBRIT project in Sweden, which uses a stainless-steel liner and currently has a modest capacity of 100 cubic meters (3500 cubic feet).[208] If successfully developed, rock caverns could have low cushion gas requirements of only 10% to 20%.[209]

In sum, there are several options to store grid-scale amounts of hydrogen underground. These can be divided between porous sites (depleted gas fields and aquifers) and cavities (salt and rock caverns). Salt caverns appear most suited option for hydrogen storage. There are salt deposits in 24 of the 50 states of the United States. They are widely distributed; some have “a lateral extent of several hundred miles,” according to the U.S. Geological Survey.[210] Given that the U.S. electricity has three large grids – the Eastern Interconnect the Western Interconnect, and the Electric Reliability Council of Texas, salt cavern storage could be widely used to support firming up the supply that is not met by solar, wind, and short-term battery storage. Further, sites are plentiful in Texas where combined heat and power is widely used due to the heavy concentration of chemical industries in the state.

For areas where salt cavern storage is not practical, less mature alternatives such as porous sites could be explored; between porous options, aquifers are more expensive because their leak-tightness needs to be mapped geologically. In contrast, depleted gas fields are more leak-proof while having a higher risk of contaminating the stored hydrogen with any residual natural gas that might be left in the field. Finally, rock caverns could pose a promising hydrogen storage solution, but they are currently only available at small pilot scales.

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[200] Tarkowski 2019
[201] Crotogino 2022
[202] IEA 2022
[203] Crotogino 2022 and IEA 2022
[204] Crotogino 2022 and Tarkowski 2019
[205] Panfilov 2016
[206] IEA 2022
[207] Tarkowski 2019
[208] Hydrogen TCP-Task 42 2023
[209] IEA 2022
[210] USGS 1962

Despite these differences, all methods share a set of drawbacks and uncertainties:[211]

- Pumping hydrogen underground for storage is more challenging than storing more commonly used gases like air and natural gas, due to the different physical properties of hydrogen.
- When stored, hydrogen can react with microbes, minerals and fluids. These reactions consume stored hydrogen and create contaminating gases that might need to be removed after withdrawing the stored hydrogen.
- Repeatedly injecting and removing hydrogen into and from reservoirs can create stresses on storage sites. Thus, the tightness of these reservoirs might be compromised over time.
- Creating, storing, withdrawing, and using hydrogen are all paired with energy losses. At current technology levels, these losses are 60% or higher. In other words, when using underground hydrogen for energy storage, the power-to-storage-to-power efficiency is below 40%.[212]
- Some amount of hydrogen is trapped in the storage reservoir as cushion gas, although this loss only occurs when initially filling the reservoir. It is in effect, a part of the capital investment in setting up the storage system. Once filled, only working gas is injected and withdrawn from the reservoir.

To further assess the potential of hydrogen as an energy storage method, we performed heuristic calculations about how much hydrogen would be needed for decarbonizing combined heat and power generation and for some peaking generation.

It would take about 2 million metric tons of hydrogen per year to replace all present fossil fuel combined heat and power generation in the United States.,[213] About 5 million metric tons of hydrogen would be needed for peaking power production in the long-term, assuming that about 2% of future long-term power generation is for peaking power produced in 60% efficient fuel cells; the rest of the variability of solar and wind is assumed to be addressed by a combination of efficiency, short-term battery storage and intra-day demand response.[214] This long-term hydrogen use amounting to 7 million metric tons per year could be summarized as follows:

- Replacement of 2021 fossil fuel-based combined heat and power: 2 million metric tons of H_2
- 2% of future peaking generation for electricity demand 30% larger than 2021: 5 million metric tons hydrogen.[215]
- Renewable electricity generation required: 350 million MWh – at times when the generation would otherwise be curtailed.

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[211] Heinemann *et al.* 2021 and Hydrogen TCP-Task 42 2023

[212] Okoroafor *et al.* 2022a

[213] Estimated from EIA 2022, Table 3.24. Assumes a one-for-one replacement of fossil fuels by hydrogen. 85% of the fossil fuel CHP uses natural gas as a fuel. The CHP systems could be combined heat and power-capable fuel cells or engines or turbines design to burn pure hydrogen. The former has the advantage of avoiding air pollution; it also has the potential for the recovering the water used to make the hydrogen if the hydrogen is produced on site near the CHP facility.

[214] Based on a detailed hour-by hour electricity model for Maryland that included all these features, as described in Makhijani 2016. Assumes that (i) electricity demand would be roughly 30% larger than at present, (ii) significant improvements in efficiency of existing uses would occur, and (iii) heating and most transportation would be electrified. The overall result indicated lower energy costs than for business as usual.

[215] This presumes electrification of road transportation and building heating which would increase demand; it also assumes that existing uses of electricity would be made much more efficient – including air conditioning and water heating. Current electric space heating can also be made much more efficient. Electricity demand might increase by as much as 50% if efficiency is not vigorously pursued.

- Avoided CO_2-equivalent emissions relative to natural gas, including 2.7% hydrogen leaks: about 80 million metric tons per year.

b. Transportation

When hydrogen is not produced at the site of use, it must be transported there. The main transportation methods are:

- By pipeline as a compressed gas, similar to the way natural as is transported today;[216]
- As liquid hydrogen by ship or rail;
- By truck as a compressed gas put into cylinders; this is a typical method envisioned for supplying refueling stations for fuel cell trucks for instance.

The first two are suitable for large-scale transport. There are currently about 1,600 miles of hydrogen pipelines associated with commodity hydrogen production and transport.[217] All three have safety issues associated with them in case of accidents or leaks. Hydrogen is flammable over a much wider range of mixtures with air than natural gas. At the same time, being much lighter than air, it rises rapidly, preventing horizontal spread of fires. As with hydrogen displacing fossil fuels, new safety risks would be created when hydrogen transport routes are established. To the extent that hydrogen replaces fossil fuel transport along these same routes, there would also be a risk reduction. The matter is similar to the environmental impacts associated with production and use – there are new site-specific risks and there is also a global balance of risk increases and decreases to be considered.

The aforementioned transportation methods involve transporting hydrogen gas or liquid directly. As an alternative to these methods, hydrogen can also first be converted to ammonia (NH_3), which can then be transported by pipeline or ship. Although converting hydrogen to ammonia would add an additional 10 to 12% to the energy required to make hydrogen, the resulting ammonia would be easier to transport than hydrogen. Turning this ammonia back into hydrogen is inefficient, causing 40% to 70% of the stored energy to be lost.[218] Consequently, transporting hydrogen in the form of ammonia is most useful if the ammonia can be used directly at its destination, instead of needing to be converted back into hydrogen. Here, the main use case of transported ammonia would be combustion to produce electricity.

On paper, burning hydrogen-derived ammonia is a zero-emissions process, creating only water and nitrogen (N_2):

$$4\ NH_3 + 3\ O_2 \rightarrow 6\ H_2O + 2\ N_2$$

However, in practice, transporting and burning ammonia can create various climate and health problems.[219] For example, incomplete combustion of ammonia produces nitrous oxide (N_2O): a powerful greenhouse gas and ozone layer depletant. N_2O can also form when ammonia leaks during transport, and is broken down in the atmosphere. The amount of N_2O production determines whether using

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[216] We are not addressing capture of CO_2 and its transportation to sequestration locations. Blue hydrogen production, by definition, has associated CCS. One of our principal recommendations is that blue hydrogen not be pursued.

[217] CRS 2023

[218] Bertagni *et al.* 2023

[219] Bertagni *et al.* 2023

ammonia for electricity production has emissions that are as low as solar electricity (with low N_2O leaks) or higher than coal-based electricity (with high N_2O leaks). Furthermore, ammonia combustion produces nitrogen oxides (NO_x), which pose health risks that already overburden marginalized communities.[220] Even current state-of-the-art ammonia combustion turbines produce NO_x levels that exceed many regulatory limits and are 10 to 100 times higher than natural gas-fired turbines.[221] Thus, using ammonia to transport the energy contained in hydrogen faces serious health and climate risks that would need to be resolved before being ready for widespread implementation.

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[220] Cushing *et al.* 2022

[221] Bertagni *et al.* 2023

VI. Assessment of Hydrogen Uses

As the previous chapters have shown, the climate benefits of hydrogen depend strongly on how this hydrogen is produced. The same can be said for different uses of hydrogen: some uses will have large climate benefits, whereas other uses might exacerbate climate change. Thus, it is important to evaluate the most prominent use cases for hydrogen. This chapter aims to provide this evaluation.

Presently, almost all of the 10 million metric tons of hydrogen produced as a commodity is used as a chemical in petroleum refining and for the production of chemicals (mainly ammonia and methanol). In these applications, significant climate benefits can be gained by substituting fossil sources of hydrogen (grey and black hydrogen) by renewable-based hydrogen (green hydrogen). Other applications involve using hydrogen as an energy carrier. Currently, almost none is used for this purpose (see Chapter II, Figure II-2), because hydrogen is mainly made from other, primary energy sources such as natural gas. Consequently, it has generally been cheaper to just use the natural gas directly. Hydrogen is being considered as a major energy source in the context of the need to decarbonize the energy system.

The present chapter will discuss hydrogen uses that involve both energy and industrial applications. First, it will cover some general considerations for hydrogen as an energy carrier and industry feedstock. Then, it will discuss the various end-use applications of hydrogen. For each of these end-use sections, an estimate will be given of how much hydrogen may be used for these applications.

a. Using hydrogen as an energy source - general

This chapter surveys the main energy uses of hydrogen as well as other major uses of hydrogen to assess the role of clean hydrogen in the decarbonization of the U.S. energy system. Since production of hydrogen today involves significant greenhouse gas emissions, it is important to include existing uses in considering decarbonization even though hydrogen use as energy source is still very small.

Our focus in considering uses is climate. The estimates of potential hydrogen use made in this chapter are mainly from that point of view. They are made with the existing level and pattern of demand of goods without an analysis of alternatives – as was noted in the preface. We also note this consideration, as appropriate, at various points in this chapter. Suffice it to say here that the levels of hydrogen use judged positive for climate change mitigation in this chapter represent a “business-as-usual” method of making estimates. For example, we do not examine an increase in steel recycling to replace the modest production of steel from iron ore remaining in the United States. At the other end, we also do not consider steel exports or even hydrogen exports in our assessment of clean hydrogen production in the United States.

Finally, for reasons discussed in Chapter IV – and as is clear from the analysis of specific uses in this chapter – we consider that as a general rule, hydrogen useful for decarbonization would be green hydrogen. One possible major temporary exception – steel – is also discussed.

Before considering specific end-uses, it is instructive to consider some general concerns about using hydrogen. The first of these relates to the different ways to use hydrogen as an energy carrier; this can be done in two ways:

- It can be burned, in a manner that is generally similar to natural gas. The details of hydrogen burning equipment differ from natural gas burning equipment, since hydrogen has a higher flame temperature and speed and is also less energy dense per unit volume. As such, hydrogen is not a simple ‘drop-in’ substitute for natural gas, because equipment designed for natural gas cannot handle pure hydrogen.

- It can be used in fuel cells to make electricity – thereby becoming part of the general trend to electrification as a principal means for achieving a decarbonized energy system. See this chapter’s section on fuel cells for a description of different fuel cell technologies. The fuel cell is basically an electrolyzer in reverse: whereas electrolyzers use electricity to split water molecules into hydrogen and oxygen (see Chapter IV above), fuel cells recombine said hydrogen and oxygen to yield water and electricity. Therefore, fuel cells and electrolyzers can be combined to store electricity in the form of hydrogen, for later use as an energy source.

Whether using hydrogen to decarbonize energy production or other chemical processes, its production must involve low greenhouse gas emissions in order to expect any climate benefits.[222] The Department of Energy calls this “clean hydrogen”. As highlighted in Chapter IV, according to the DOE Clean Hydrogen Production standard, hydrogen is considered clean if it meets the following 2 criteria:[223]

- Two kilograms of carbon dioxide equivalents (CO_2-eq) of greenhouse gas emissions per kilogram of hydrogen at the production site;
- Four kilograms of CO_2-eq emissions on a ‘well-to-gate’ basis, which includes emissions that occur upstream of the production site. Such emissions could be energy emissions involved in obtaining and transporting feedstocks for hydrogen production. Some downstream emissions are also included, such as “processes associated with ensuring that CO_2 produced is safely and durably sequestered.”[224]

These metrics are reasonable in the sense that direct burning of natural gas with the same energy content as a kilogram of hydrogen would result in about 6 kg CO_2 emissions from burning the natural gas and over 10 kg CO_2-eq total when methane leaks in the natural gas system are taken into account.[225]

There are however two major technical deficiencies in the DOE guidance:

- It does not consider the warming impact of hydrogen leaks. As we have seen in Chapter III, hydrogen, while not a greenhouse gas itself, exerts a significant warming impact in indirect ways. Beyond a certain level, leaks can negate any climate change mitigation impact of displacing fossil fuels.
- The draft guidance is based on Argonne National Laboratory’s GREET model, which uses a 100-year global warming potential for methane even though the target time frame for achieving a net-zero-greenhouse-gas-emissions energy system is 2050; this means the vast majority of emissions must be eliminated in the next 20 years. As is also discussed in Chapter III, the use of the 20-year warming potentials for methane, the main constituent of natural gas, is therefore essential.[226]

A third problem is the assumption of an extremely high efficiency of 96% for CCS in the Argonne GREET model used to calculate emissions. Blue hydrogen could not meet the DOE clean hydrogen standard with

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[222] This caveat would not be applicable if large reservoirs of natural hydrogen that can be economically recovered are found. The necessity of keeping leaks low to avoid negative climate impact would still apply.

[223] DOE Standard Guidance 2023

[224] DOE Standard Guidance 2023, page 3

[225] Calculated at 2.7% and 20-year GWP of methane).

[226] Consistent calculations of CO2-equivalent values requires the use of the same time-frame for global warming potentials for all greenhouse gases. The GWP is a relative measure, with the GWP of CO2 always being set equal to 1. For a list of GWPs calculated with various time frames, see IPCC 2021, Table 7.15, p. 1017.

more realistic CCS efficiency estimates based on experience outside the use of captured CO_2 to stimulate oil production unless natural gas leaks were reduced far below the current average level of 2.7%.

Having re-emphasized these limitations in assessing hydrogen production, we now proceed to evaluate various end uses of hydrogen.

i. *Efficiency considerations*

Just like hydrogen production involves energy losses (Chapter IV), there are also losses at the other end: when hydrogen is used. Consider for instance battery and fuel cell vehicles; both have been developed for road transportation applications and other applications such as fork lifts, ferries, and tractors. Notably, they differ in their charging (fueling) and discharging efficiency. This efficiency difference is relevant, even though the point-of-use and overall emissions are zero if both battery charging and hydrogen production are from renewable sources. Instead, efficiency impacts the speed of decarbonization, because the overall efficiencies of the battery and fuel cell systems are very different.

The efficiency for producing hydrogen from electricity is about 60% to 70%. In other words, roughly two thirds of the energy in electricity gets converted to compressed hydrogen on-board a vehicle. Using this energy in fuel cells has an efficiency of 40% to 60% range for transportation applications. Thus, the overall roundtrip efficiency for hydrogen vehicles is in the 30% to 50% range. Thus, from electricity generation to the wheels of the vehicle, about half to two-thirds of the renewable electricity is lost.

Using batteries is generally more efficient.[227] Specifically, the roundtrip efficiency of a lithium-ion battery-powered vehicle depends on age and battery chemistry as well as charging and use patterns. For example, a recent evaluation of battery efficiency deterioration over the life of the vehicle suggests that battery efficiency decays from an initial efficiency of 90% to an "End of Life" efficiency of 75%. Assuming a linear decline and constant annual mileage, this gives an average roundtrip efficiency of 82.5%.[228] Thus, a given amount of renewable energy (and the resources needed to generate it) can power roughly twice as many vehicles (or go twice as many miles) as fuel cell vehicles. In short*, barring other considerations, such as energy required for heating and cooling the vehicle, battery-powered vehicles would lead to a faster and more efficient energy transition than fuel cell-powered vehicles would.*

The situation is similar for most other applications. For instance, it is much more efficient to use solar electricity plus battery storage for meeting electricity demand in the early evening hours in the summer than making hydrogen and using it in fuel cells. The higher efficiency of renewable energy plus storage also generally results in far lower operating costs – sufficient to make up considerable differences in initial cost of comparable systems, as we illustrate in the transit bus analysis (Section d below).

So long as there is demand for renewable electricity to displace fossil fuels directly, it is generally more efficient and economical and much more effective for decarbonization to use the electricity directly, with or without battery storage. In the longer term with the grid approaching decarbonization, there will be seasonal surpluses of energy and the potential of hydrogen would likely increase, because it is a long-

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[227] There are long-duration storage batteries – such as a 100-hour iron-air battery now near commercialization – that have roundtrip efficiencies that are similar to hydrogen use in fuel cells. In such cases, the selection of technology is more complex – See Makhijani *et al.* 2024, forthcoming.

[228] Koroma *et al.* 2022

duration storage technology. This is illustrated in the section on peaking generation in the long-term later in this chapter.

For this reason, hydrogen for use in light-duty vehicles, delivery vehicles, heating buildings, and other applications where electricity can directly be used would be a setback to decarbonization. We will not discuss such applications, other than mentioning them in passing when appropriate.

We estimate potential hydrogen demand in this framework that gives priority to efficiency and energy system decarbonization and compare it to the Department of Energy's draft hydrogen strategy in the last section of this chapter.

b. Hydrogen in carbon-intensive heavy industry

i. Ammonia

Ammonia is a molecule composed of one nitrogen atom and three hydrogen atoms, such that its chemical formula is NH_3. This molecule is widely used as a synthetic fertilizer, and is produced at large scales from hydrogen and nitrogen gas using the highly energy-intensive Haber-Bosch process:

$N_2 + 3\ H_2 \rightarrow 2\ NH_3$

About 14 million metric tons of ammonia were produced in the United States in 2019, including that internally generated in petroleum refining and other chemical industries.[229] About 3.0 million metric tons of hydrogen would be required to produce ammonia at the 2019 level;[230] currently, essentially all of this is grey hydrogen. As a result, about 60% of ammonia production in the US occurs in Louisiana, Texas, and Oklahoma because of the proximity of natural gas fields. The three-part combination of grey hydrogen feedstocks, high energy-intensiveness of the Haber-Bosch process, and the sheer scale of hydrogen production mean that ammonia production currently accounts for 1% of global energy consumption and 1.4% of global CO_2 emissions.[231] Part of these emissions can be mitigated by producing the required hydrogen more sustainably. Thus, the DOE's hydrogen "liftoff" report describes replacing hydrogen for ammonia and other uses in the chemical industry with "clean" hydrogen as having "Strong potential" for decarbonization, defined as areas with "few alternatives to decarbonization without H_2".[232]

Assuming that no hydrogen leaks or (in the alternative) assuming that any leaked hydrogen is flared (burned), the emissions associated with the hydrogen production for ammonia would be about 44 million metric tons of CO_2-eq (using a 20-year warming potential for methane and a leak rate of 2.7%).[233] Essentially all of this climate impact could be eliminated by replacing the grey hydrogen by green hydrogen over time; this would take approximately 15 GW of electrical input (at 100% capacity factor) to

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[229] USGS 2020

[230] The amount of hydrogen used for ammonia in 2015 was 2.077 million metric tons (Brown 2016, Table 1) for a production amount of 9.56 million metric tons (USGS 2020) The 2019 production was 14,000 metric tons (USGS 2020). On a proportional basis, 3.0 million metric tons of hydrogen would therefore be required for production at the 2019 level.

[231] Capdevila-Cortada 2019

[232] DOE 2023a, Figure 1, page 8

[233] Calculated from the Argonne 2022, adjusted for a natural gas leak rate of 2.7% (instead of 1%) and a 20-year GWP for methane (instead of 100 years). This gives a rate of GHG emissions of 14.6 kg CO_2-eq per kg H_2, resulting in about 44 million metric tons of CO_2-eq emissions (rounded) for 3 million metric tons of hydrogen.

produce 3 million metric tons of hydrogen per year.[234] This replacement would be feasible in Gulf Coast States, which have high offshore wind energy potential and,[235] in the case of Texas, also high solar energy potential. As wind and solar energy grow, the amount of curtailed renewable energy will also grow – as discussed below (Section "f." of this chapter) far larger amounts of hydrogen could be produced when using these curtailed renewables.

In contrast, replacing the grey hydrogen with blue hydrogen would only reduce the greenhouse gas pollution by about 40%. Illustrating this point, Figure VI-1 shows the emissions associated with producing grey, blue, and green hydrogen for the 14 million tons of ammonia produced in 2019 (this would require 3.0 million tons of hydrogen). For the purpose of comparison, we have also shown the emissions if grid electricity, with 2021 national average emissions were used to produce the hydrogen. This option yields the most greenhouse gas emissions, both because it takes a great deal of electricity to produce hydrogen (45 to 50 MWh per metric ton) and because emissions of the present fossil-based electricity grid are still high.[236] As the grid transitions to decarbonization, the corresponding emissions would decline and eventually be zero with a fully decarbonized grid.

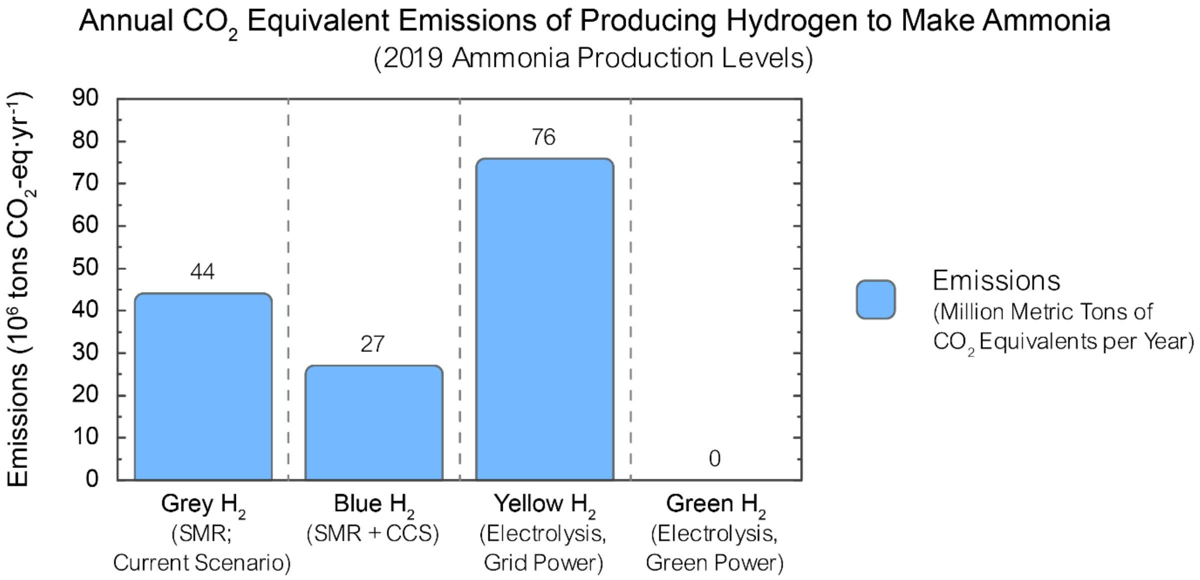

Figure VI-1: Methods of hydrogen production and the potential reduction of warming impact by transitioning from grey to blue or green hydrogen for ammonia production at the 2019 level of 14 million metric tons (3.0 million metric tons of hydrogen). GWP for methane 82.5. Hydrogen leaks assumed to be flared. Upstream emissions included. Capital investment indirect emissions not included. Methane leaks attributable to grid electricity generation system have been included.
Source: IEER calculations based on 2.7% methane leaks, 20-year methane warming potential and Argonne 2022 for other emission estimates (see Figure IV-4 above).

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[234] This assumes a 75% electrolyzer efficiency, and 100% operating capacity factor.

[235] NREL 2022b

[236] National average CO_2 emissions are about 0.41 metric tons CO_2 per MWh. Natural gas was 38% of generation in 2021. When leaks amounting to 2.7% of use are added, the emission coefficient rises to 0.54 mt CO_2-eq/MWh, using a 20-year GWP for methane.

Figure VI-1 shows that using blue hydrogen for ammonia production would reduce emissions compared to grey hydrogen if carbon sequestration can be assured.[237] However, blue hydrogen does not fully decarbonize ammonia making and risks maintaining emissions over a long period of time. After all, making blue hydrogen requires CCS investments which, like other investments in heavy industry, are designed to pay back over decades. This payback time leads to a phenomenon known as 'lock-in', in which there is pressure to use fossil-based assets are used for their full economic lifetime because it is profitable to do so.[238] As a result, using blue hydrogen to make ammonia would reduce greenhouse gas emissions in the short term by displacing grey hydrogen, but would also create long-term emissions that could be avoided if green hydrogen were used instead. If blue hydrogen infrastructure is built out instead, climate goals might require these assets to be abandoned early to avoid long-term emissions, resulting in significant stranded costs to society that will be borne by ammonia consumers, or taxpayers, or shareholders or some combination.

Ammonia has also been considered as a hydrogen storage molecule and as a fuel for long-distance shipping. These uses are briefly covered in section f of this chapter and in section b of chapter V, respectively.

Were grey hydrogen for ammonia production at the 2019 level of 14 million metric tons replaced by green hydrogen, the requirements and impacts would be as follows:

- Green hydrogen required: 3.0 million metric tons
- Climate impact: reduction of CO_2-eq emissions of about 44 million metric tons;
- Renewable energy required: 190 MWh of electricity, or about 3.4% of US generation in 2021 – this could all eventually be supplied by solar and wind energy that would otherwise be curtailed;[239]
- Natural gas consumption reduced: about 470 billion cubic feet or about 1.4% of US production in 2019.[240]

Three million tons of hydrogen in 2050 represents a static ammonia demand – mainly for synthetic fertilizers. Such an outcome is possible if farming undergoes changes in the direction of reduced use of synthetic chemicals. But it is also possible that ammonia demand in agriculture may increase. The Department of Energy's upper end of ammonia production implies 5 million metric tons of clean hydrogen production per year.[241] This is not unreasonable given that ammonia demand has grown.[242] On the other hand, growth of organic farming and precision application of nitrogen fertilizers to reduce runoff may reduce the amount of nitrogen needed in farming. We have not independently analyzed

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[237] CCS is a vast topic technically, economically, and environmentally. It deserves its own detailed assessment on a scale similar to this report on hydrogen, for a potential future report. For the present we refer the reader to three blog posts – Makhijani 2022a, Makhijani 2022b, and Makhijani 2022c.

[238] Sato *et al.* 2021

[239] Assuming 47 MWh of electricity per metric ton of H_2. Electricity production data are available at https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php

[240] Assuming 70% efficiency for grey hydrogen production. Natural gas production data are available at https://www.eia.gov/dnav/ng/ng_sum_snd_a_EPG0_FPD_Mmcf_a.htm

[241] DOE 2022, Figure 12

[242] USGS 2020

ammonia demand and adopt the upper figure as the high-end estimate for the purposes of estimating how much hydrogen might be required.

The example shows both the potential climate mitigation of replacing grey hydrogen with green hydrogen. But it represents only 15% of the Department of Energy target of 20 million metric tons of “clean” hydrogen by 2040.[243]

ii. Methanol

A similar approach to ammonia decarbonization with green hydrogen could be applied to the other major chemical production use of hydrogen: methanol production. Doing so would add about one million tons per year to the green hydrogen requirement. The overall use of methanol may be expanded in the future, in particular to replace fuel oil in large ocean-going ships.[244] This is discussed further in the Transportation section below).

iii. Petrochemical refining

We have not included commodity hydrogen use for petroleum refining in the above calculations because the use of refined petroleum products like diesel, gasoline, and fuel oil for heating buildings needs to decline rapidly if the goal of net zero CO_2-eq. emissions by 2050 is to be met. The DOE hydrogen strategy does not show any clean hydrogen use (other than that which might be internally generated) in the refining industry in the year 2050.

Given the large role of petroleum products in all these areas, the transition will take some time. However, the analysis of the transition, and hence any corresponding hydrogen requirements, and the fraction of those requirements that would come from commodity hydrogen (rather than internal generation in the industry) is beyond the scope of the present report.

iv. Steel

Hydrogen can help decarbonize steel production, which accounts for approximately 7% to 9% of global annual CO_2 emissions and therefore needs to change to meet climate goals.[245] Steel is an area that the DOE “liftoff” report classifies as having strong potential for decarbonization.[246]

To understand the role of hydrogen, it is useful to view the initial steps of steelmaking as a two-part process that consists of “reduction” and “transformation.”[247] In the reduction step, iron ore is “reduced” to metallic iron by exposing it to a reducing agent: generally coke, a fuel made from coal. The resulting iron often contains carbon and metal impurities, which are removed in the transformation step that produces steel. The vast majority of steel’s CO_2 emissions are produced during these reduction and transformation steps, the more so in the first one.

In conventional steelmaking, the reduction step involves putting iron ore, coke, limestone into a blast furnace to produce “pig iron”, which is metallic iron containing about 4% carbon and other minor impurities. Pig iron is then typically transformed into steel in a basic oxygen furnace, which uses oxygen to lower the iron’s carbon content to 2% or less. Because this steelmaking process uses a blast furnace

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[243] DOE 2022, Figure 12

[244] Worley 2021

[245] Kim *et al.* 2022

[246] DOE 2023a, Figure 1, page 8

[247] Koch Blank 2019

(BF) and a basic oxygen furnace (BOF), it is typically abbreviated as BF-BOF. This process emits CO_2 in the blast furnace when coke is converted into CO_2 and in the basic oxygen furnace when reacting oxygen with carbon impurities in the iron.

Since hydrogen is a reducing agent, it can be used to replace coke in the process of reducing iron ore. The process is called hydrogen-based direct reduction (H-DR), and the product is called "direct reduced iron". H-DR exposes iron ore to hydrogen, which produces "sponge iron" that can be processed into steel in an electric arc furnace: a technology now widely use to recycle scrap steel. Since this second step can be powered directly be renewable electricity, we focus here on the use of hydrogen to produce direct reduced sponge iron. H-DR steelmaking is being scaled up by various companies.

We compare the greenhouse gas emissions using hydrogen from electrolysis for various electricity sources with those from the BF-BOF process (Figure VI-2). The following cases are shown:

- Base case: the current blast furnace-basic oxygen furnace (BF-BOF) process;
- Electrolytic hydrogen with grid electricity : Electrolytic hydrogen made using grid electricity for iron ore reduction followed by an electric arc furnace (EAF) to produce raw steel;
- Grey hydrogen for reduction plus grid electricity for EAF;
- Blue hydrogen for reduction plus grid electricity for EAF;
- Green hydrogen for reduction plus grid electricity for EAF;
- Grey hydrogen for reduction plus decarbonized electricity for EAF;
- Blue hydrogen for reduction plus decarbonized electricity for EAF;
- Green hydrogen for reduction and decarbonized electricity for EAF.

As Figure VI-2 shows, the degree to which hydrogen can reduce greenhouse gas emissions by replacing coke will depend in large measure on the source of the hydrogen: in all cases except using 2021 US national grid electricity to make hydrogen electrolytically, using hydrogen for steelmaking reduces greenhouse gas emissions. This reduction reflects the fact that hydrogen is much more effective at reducing iron than coke, requiring only 40% of the energy to reduce iron ore compared to the present use of coke in blast furnaces.[248] In fact, in regions where the electricity supply has lower emissions than the national average, some reduction in emissions would be achieved if grid electricity is used to electrolytically make hydrogen and use it to produce steel. These emissions per metric ton of steel for electrolytically produced hydrogen will automatically decline as the energy transition progresses, going to zero when the grid is completely decarbonized. Equivalently, using a dedicated renewable energy supply for hydrogen production could reduce emissions to zero.

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[248] Devlin and Yang 2022

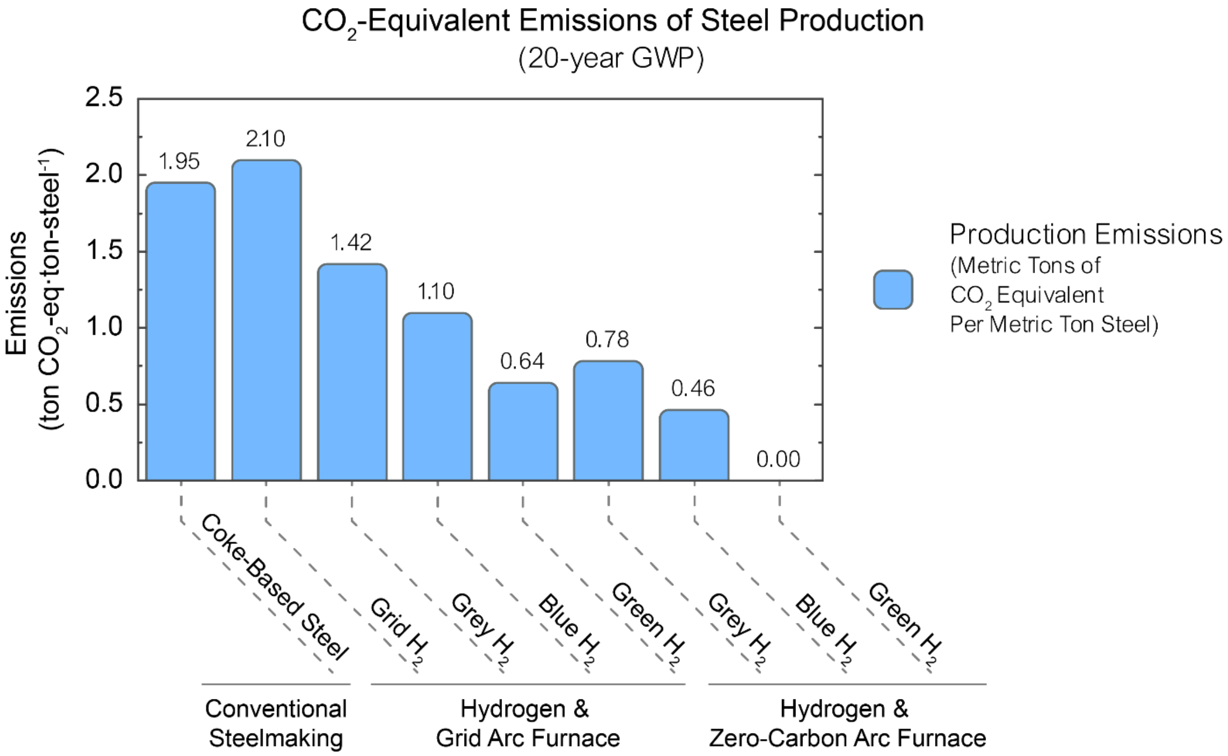

Figure VI-2: Greenhouse gas emissions per metric ton of steel using hydrogen reduction (including electricity for the Electric Arc Furnace) compared to today's BF-BOF approach (labeled "Coke-Based Steelmaking"). Arc furnace uses either grid electricity or zero-carbon renewable electricity, as noted underneath the column labels. Grid electricity emissions taken as 0.54 mt CO_2-eq/MWh, including 0.13 mt CO_2-eq/MWh for methane leaks (20-year GWP). Sources: Fischedick et al. 2014 for BF-BOF method; Devlin and Yang 2022 for direction reduction energy requirements except hydrogen; Bhaskar et al. 2020 for hydrogen requirements.

Furthermore, Figure VI-2 indicates that using hydrogen for steel production from iron ore is so much more efficient than coke that even grey hydrogen can reduce CO_2-eq emissions in steel production by almost 30% even when a 20-year GWP is used for natural gas. Thus, hydrogen-based steelmaking is an unusual example where both grey and blue hydrogen could reduce emissions relative to the dominant current technology. If grid electricity is used for power requirements (including for the electric arc furnace), using blue hydrogen would reduce greenhouse gas emissions per metric ton of raw steel by over 40%. Emissions are further reduced when powering electric arc furnaces with renewable electricity instead of grid power. For example, grey hydrogen with zero-carbon electricity would reduce emissions by 60% with respect to conventional steelmaking.

If grey hydrogen is not available at the steel plant, conversion to green hydrogen is the best climate option. However, if grey hydrogen is available, an interesting policy question arises: should steelmaking transition to use grey hydrogen till green hydrogen is available, or should the steel plant be converted to blue hydrogen by adding CCS (presuming that is technically feasible) followed by a conversion to green hydrogen? Zero emissions is assumed to be the goal in both cases.

When evaluating this question, one should consider that it will take time to build CCS in the best of circumstances, and some hydrogen plants may not have enough space available to site a CCS unit.[249] In other words, retrofitting grey hydrogen plants with CCS would be a relatively costly and complicated endeavor, while the benefits of CCS may be marginal. Adding to this poor climate benefit, CCS is widely opposed due to the added environmental burdens it imposes on frontline communities.

The United States produced 17 million tons of steel from ore in 2020.’[250] As noted in Figure VI-2, converting this portion of the US steel production mix to electrolytic hydrogen produced with grid electricity (national average) would not yield reduction in emissions. However, direct reduction with green hydrogen combined with grid electricity would reduce GHG emissions by about two-thirds, with the remaining emissions declining to zero as the local electricity supply is decarbonized or if dedicated renewable energy is procured.

The total potential for reducing GHG emissions at the 2020 level of steel production from iron ore (17 million metric tons) is about 33 million metric tons. This could rise if the United States reduces its net imports of steel and manufactures more steel from iron ore domestically. The trade deficit in 2019 was 19.2 million metric tons.[251] If produced in the conventional way with coal, steel production emissions could double to 66 million metic tons of CO_2-eq. This number therefore represents the potential reduction emissions reduction using green hydrogen.

Alongside reducing CO_2 emissions, H-DR would also provide a crucial environmental justice benefit: improved air quality. This benefit arises from H-DR not using coal or coke, which are both polluting feedstocks that are essential to BF-BOF. For example, non-renewable steelmaking and coking plants in Canada and Italy have been found to emit NO_x, SO_2, polyaromatic hydrocarbons and fine particulates.[252] Such emissions negatively affect heart and lung function,[253] and have been linked to excess mortality in Italy.[254] Likewise, a coke plant in North Birmingham, Alabama was found to pose: “a significantly higher environmental health risk than other facilities [in the area].”[255] Using H-DR to substitute coke-fed BF-BOF could therefore improve the air quality for frontline communities. Air quality improvements and associated health benefits would be rapid: the 2016 closure of a coke plant in Pittsburgh caused a significant drop in sulfur dioxide and fine particulate emission levels, which corresponded with reduced cardiovascular hospitalizations and emergency room visits in the area over the course of three years.[256]

Similar benefits would be provided by a low-emission steelmaking technology called molten ore electrolysis (MOE), in which iron ore is molten and reduced to iron directly using electricity. Electrolytic steel production is also called “electrowinning”. Although being less-explored by industry than H-DR,[257] MOE is considered by some to be a viable method to replace traditional steelmaking methods.[258]

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[249] Grubert and Sawyer 2023

[250] Devlin *et al.* 2023. The remaining amount of U.S. steel production was from scrap. As noted, the production of steel from scrap can be done in an electric arc furnace and requires no hydrogen.

[251] DOC 2020

[252] Shutt *et al.* 2017, Dales *et al.* 2013, Liberti *et al.* 2006 and Parodi *et al.* 2005

[253] Dales *et al.* 2013 and Shutt *et al.* 2017

[254] Gennaro *et al.* 2022

[255] Allen *et al.* 2019

[256] Yu and Thurston 2023

[257] Muslemani *et al.* 2021

[258] Koch Blank 2019

It is possible that MOE and H-DR will coexist in a future decarbonized steel industry. A pilot plant using a version of this technology called Molten Oxide Electrolysis, is to be expanded by Boston Metal, which has investors that include the global steel corporation ArcelorMittal.[259] The target date for commercial operation is 2026.[260] The company is setting up operations in Brazil not only for steel production but for using the process to extract a variety of metals from mining wastes.

We have not examined Molten Oxide Electrolysis in detail since it is a nascent technology. We estimate that electrolytic reduction of iron ore followed by processing in an electric arc furnace would require on the order of 6 MWh of electricity – roughly 50% more than that required for hydrogen reduction followed by the electric arc furnace. This is a preliminary estimate made for this study based on a variety of sources; the amount of electricity needed could be reduced as process efficiency improves.

As an important alternative to producing 'virgin steel' from ore as described above, one can recycle scrap steel using electric arc furnaces. This type of steel production is the dominant steelmaking method in the U.S. because a large amount of scrap steel is available (as it also is in many European countries). In contrast, countries in the Global South, such as China, India, China, and Brazil are still industrializing and building up their infrastructure, buildings, and transportation. These countries therefore produce most of their steel from ore. Their proportion of scrap can be expected to rise over the decades, but there is a strong case in the context of decarbonization to convert BF-BOF steel production to green hydrogen to address the 7% of global CO_2 emissions that are attributable to the reduction of iron ore to pig iron production.[261] Devlin and Yang (2023) estimate that, as the stock of steel in the Global South increases, recycling would rise from the present 22% to 50% by 2050.

There may be potential for more steel to be recycled in the United States thus avoiding the use of hydrogen and reducing the use of energy. Devlin and Yang (Table 1) estimate that 83 million metric tons of steel are not recycled. The Steel Recycling Institute estimates that between 68% of construction rebar and 59% of other construction steel is recycled, compared to 97% of structural steel.[262] The United States appears to have enough recycled steel to replace that made from ore and also the steel that is imported. Whether this can be done economically and other large socio-economic questions are beyond the scope of this report. We provide the data here to illustrate that alternatives to hydrogen need to be considered even where its use is clearly superior on climate, environmental, and health grounds.

Finally, it is important to note that making zero-GHG-emission steel using green hydrogen will still have large environmental impacts in mining and processing ore; these can also be avoided if steel is recycled. In the case of the United States, the total amount of surplus scrap available is estimated at 83 million metric tons per year, which is almost five times the steel production from ore – 17 million metric tons per year.[263] Finally, steel production can also be complemented by efficiency in the use of steel to reduce requirements, in a manner similar to the energy sector where efficiency complements renewable energy production. The potential appears to be quite high:[264]

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[259] Boston Metal 2023

[260] Boston Metal 2022

[261] Devlin *et al.* 2023. Additional emissions are associated with the electricity needed for the electric arc furnace to get the raw steel that can be fashioned into a variety of products – or further processed into specialized alloys.

[262] AISI and SMA 2021, page 6

[263] Devlin *et al.* 2023, Table 1

[264] Devlin *et al.* 2023, page 1

> Exhaustive material efficiency measures of steel-containing products, including enhanced durability, reusability, and minimalist design, could reduce primary (ore-based) steel demand, potentially by up to 40%.

A more sustainable steel industry from an environmental standpoint would therefore focus on reducing overall steel use with greater efficiency, while maximizing recycling to produce steel in order to minimize the production of steel from mined ore. For the portion produced from ore, the currently available approach would be to use green hydrogen; molten ore electrolysis, should it be commercialized in the near future might be an alternative to be examined at that time.

v. Cement

Cement is one of the difficult sectors to decarbonize deeply. It is also among the most important, since cement is the world's principal construction material: more than 4 billion tons are produced worldwide each year. It is responsible for about 7% of global CO_2 emissions, totaling about 2.5 billion metric tons a year.[265] Cement-related CO_2 emissions in the U.S. economy were 69 million metric tons in 2015 and slightly higher than 70 million metric tons in 2020,[266] amounting to about 1.5 to 2% of total CO_2 emissions. The DOE "liftoff report" classifies cement has having "some potential" for decarbonization, defined as an application where "H_2 can contribute to decarbonization".[267]

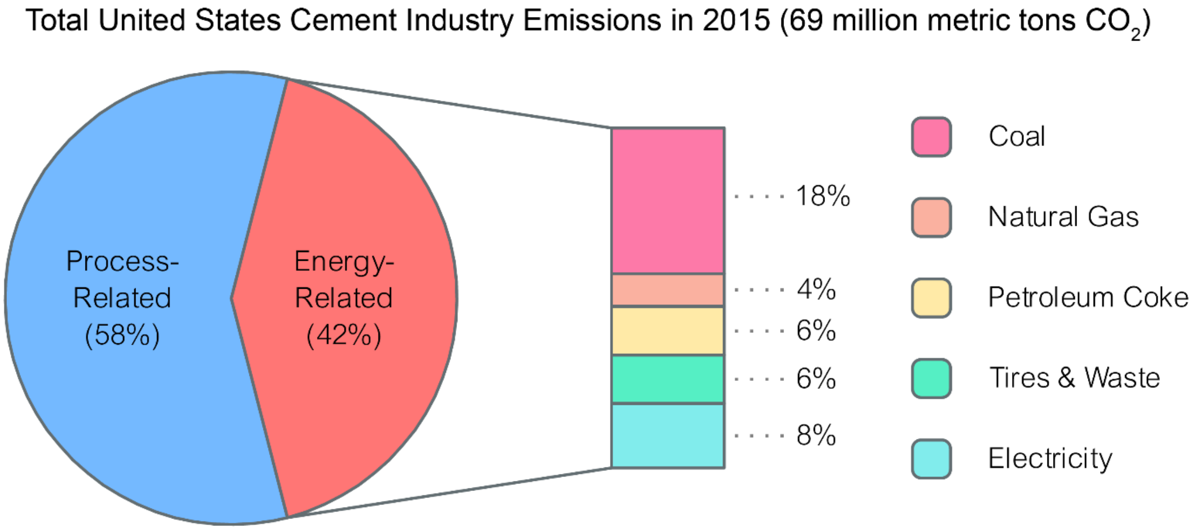

Figure VI-3. U.S. cement industry CO_2 emissions, million metric tons and percent. Source: DOE 2022, p. 134.

The cement sector illustrates how complex decarbonization can be. This complexity is caused in part by the emissions stemming from two distinct parts of the cement production process (Figure VI-3): direct emissions from the production process (58%) and emissions for using the energy required to drive production, notably high temperature heat (42%). The process emissions (58%) derive from limestone (calcium carbonate), which is an essential raw material that is heated to make lime (calcium oxide). This

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[265] IEA 2023

[266] DOE 2022, page 135

[267] DOE 2023a, Figure 1, page 8

reaction releases CO_2, which is unavoidable unless the amount of required calcium carbonate is reduced. In addition, this process requires high temperatures; producing these temperatures leads to high CO_2 emissions, and decarbonizing industrial heat production remains a significant challenge.

Decarbonizing process emissions by examining cement substitutes or methods that do not require limestone is beyond the scope of this report, but these options are noted to reflect the importance of decarbonizing a crucial and highly CO_2-intensive industry. Within the existing limestone-intensive framework of cement production, CO_2 capture has been proposed as a method to reduce net emissions without fundamentally changing the cement-making process. This captured CO_2 could be used to make a variety of chemicals, including fuels for aircraft and ships. For instance, CO_2 and hydrogen can be combined to make methanol for instance. These methods are still in the research phase.[268] These approaches reduce but do not eliminate the CO_2 emissions problem. The synthetic fuel from captured CO_2 avoids emissions that would result from burning jet fuel, but the cement CO_2 emissions wind up in the atmosphere when the synthetic jet fuel is burned.

Methods to react hydrogen and CO_2 at high temperatures to produce synthetic fuel are being developed independently of the cement industry. A small pilot plant in Germany has demonstrated fuel production in which both water and CO_2 are captured from the air.[269] However, it is unclear if these methods might connect with the cement industry to mitigate the CO_2 emissions problem.

The aforementioned sections discuss how hydrogen might help reduce direct CO_2 emissions from the conversion of limestone to lime. However, as outlined in Figure VI-3, additional cement production emissions are associated with energy use. Of these remaining 42% of emissions, the vast majority is the need for high-temperature heat in the cement-making process. In 2015, about 23 million metric tons of CO_2 emissions came from burning fuels, mainly coal, and 6 million metric tons from the use of electricity, which is used mainly for large motors that drive the mills that crush raw materials, run the belt conveyors, etc. Since the Biden administration's goal is to decarbonize the electricity grid by 2035, the electricity-related emissions would decline to zero by that time, except for any on-site generation that could be replaced by renewable electricity (via on-site generation or renewable energy power purchase agreements). These aspirational emissions reductions would leave the production of high-temperature heat as the main source of remaining energy-related emissions.

High-temperature heat is required in the so-called 'pre-calciner' and the cement kiln, which operate at different temperatures. In the pre-calciner, where raw materials are heated, temperatures are under 1000 °C (about 1800 °F) but still can be as high as 900 °C. In the "burning zone" of the cement kiln, temperatures are over 1500 °C.[270] In this kiln, pre-heated combustion gases are injected and chemically react to form 'clinker': an intermediate material that can be ground and processed into cement. Currently, research is underway to electrically produce the heat required in the pre-calciner and kiln, but no scalable electricity-based heating option is currently available. The Department of Energy's industrial decarbonization plan estimates that electrification of process heating could begin commercially in the mid-2030s.[271]

The scale of CO_2 emissions and the lack of commercial electrification options in the near-term would seem to make hydrogen produced with renewable electricity a good candidate fuel for decarbonizing

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[268] Rumayor *et al.* 2022

[269] Schäppi *et al.* 2022

[270] EPA 2022, Table 11.6-10

[271] DOE 2022, page 133

the energy part of cement production. However, the burning this hydrogen to produce heat for cement production presents significant technical issues that have not been solved. Specifically, hydrogen burns differently from the carbonaceous fuels now used and clinker production in cement kilns depends critically on the temperature distribution and heat transfer within the kiln. The DOE also notes that "[a]nother potential problem is acidification—as the gas is cooled, nitrogen oxides, sulfur oxides, and chlorine may form, and higher moisture content in the exhaust gases going to the main baghouse may cause damage."[272] Such emissions would also cause public health impacts.

An alternative to burning pure hydrogen for heat would be to use natural gas that contains a small fraction of hydrogen. As will be outlined in the next section, using such low proportions of hydrogen will does not significantly reduce greenhouse gas emissions and will therefore not solve the address the core of the problem of decarbonization of cement production. Regardless of the exact cement decarbonization solution, the rapid development of the use of electricity, pure hydrogen, high temperature solar thermal energy for heat would have wider implications than mitigating CO_2 emissions alone. These consequences stem from current cement-making fuels encompassing fossil fuels, tires, and hazardous chemical wastes. According to the EPA, burning these fuels produces dozens of inorganic pollutants, including mercury, lead, arsenic, sulfur dioxide, sulfur trioxide, nitrogen oxides, and hydrochloric acid. The EPA also lists dozens of organic pollutants, including non-methane volatile organic compounds, benzene and dioxins.[273] These organic and inorganic pollutants add to the environmental burden caused by fine particulate emissions associated with cement dust itself. In short, substituting typical cement-making fuels would constitute significant environmental justice benefits, given that cement plants are "typically [located] in low-income disadvantaged communities."[274]

In conclusion, hydrogen may help decarbonize the cement industry in part, but there remain a number of issues still to be addressed to establish the feasibility and scalability of the decarbonization.

c. Using hydrogen as a natural gas substitute

As hinted at in the previous section, hydrogen can be mixed with natural gas for distribution in the existing natural gas network. Mixing hydrogen with natural gas for use in power production and in residential and commercial buildings is among the possibilities with "some potential" for decarbonization in the DOE's hydrogen "liftoff" report.[275] Mixing hydrogen with natural gas up to 20% by volume for distribution in existing infrastructure is widely considered. An American Gas Association-sponsored study has suggested that this fraction could be increased to 50%.[276]

This application would involve burning hydrogen in homes for heating or cooking, or in gas turbines to produce electricity. Although the scale of these applications is different, both come with concerns that relate to the burning of hydrogen. These issues might appear unexpected, because, in principle, hydrogen combustion uses oxygen and only produces water:

$2\ H_2 + O_2 \rightarrow 2\ H_2O$

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[272] DOE 2022, page 145 and 146
[273] EPA 2022
[274] DOE 2022, page 133
[275] DOE 2023a, Figure 1, page 8
[276] ICF 2023

However, any type of combustion in air creates nitrogen oxides as byproducts, since air consists of 21% oxygen and 78% nitrogen. At the high temperatures produced by flames, chemical reactions produce nitric oxide (NO) and nitrogen dioxide (NO_2). These molecules are collectively referred to as NO_x, and are air pollutants with adverse health effects.[277] NO_x production typically increases at higher temperatures, and hydrogen flames typically burn at higher temperatures than natural gas flames. Furthermore, the amount of NO_x formation depends on fuel-to-air ratios and combustor technology. When substituting natural gas with hydrogen, the flame temperature, optimal fuel-to-air ratio and ideal combustor configuration will change. Therefore, substituting natural gas for hydrogen creates the risk of increased NO_x pollution in many cases, unless equipment is designed specially to limit NO_x production.

Another noteworthy challenge is leakage. As discussed in Chapters III and V, hydrogen leaks exacerbate global warming. In addition, hydrogen leaks from commonly used gas infrastructure at higher rates than methane does: an extensive literature review and experimental study commissioned by the California Public Utilities Commission (CPUC) indicates that hydrogen can leak through cracks, joints, seals and threads at rates 3.8 to 4.6 times higher than natural gas.[278]

Furthermore, blending is often pitched as a way to reduce the climate impacts of natural gas. However, many studies suggest that only up to 20% of hydrogen can be blended into natural gas, whereas the aforementioned CPUC study concludes that hydrogen blending "becomes concerning as hydrogen blending approached 5% by volume":[279] at higher hydrogen percentages, end-use appliances may need to be modified, and older components and materials may be at risk of physical and chemical degradation by hydrogen.[280] In addition, a Spanish study found that upgrading natural gas structure for hydrogen blending in the country would cost $100 million to accommodate 5% hydrogen, and over $750 million to accommodate 20% hydrogen.[281] Thus, it is unclear whether adding hydrogen even in a 5% to 20% range, as is often proposed, is a suitable option for cost and safety reasons. Further, when burning hydrogen-blended natural gas, the majority of burnt material is still natural gas that emits CO_2 and has associated natural gas leaks. The climate benefit is marginal to nil, as discussed below.

In addition, when blending hydrogen, more hydrogen-natural gas mixture would have to be pushed through the gas distribution system to maintain a given rate of energy flow, which means increasing the pressure of the gas mixture relative to supplying natural gas alone. This complication relates to natural gas being more than three times as energy-dense per unit volume as hydrogen. Therefore, when hydrogen is mixed into natural gas, the overall energy density of the mixture decreases. Figure VI-4 shows the energy per cubic foot in a hydrogen natural gas mixture compared to 100% natural gas as the fraction of hydrogen increases.

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[277] EPA 2016

[278] Penchev *et al.* 2022

[279] Penchev *et al.* 2022, page 4

[280] Examples of degradation include hydrogen embrittlement of steel components or degradation of polyethylene gas pipes.

[281] Martin 2023a and SEDIGAS 2023

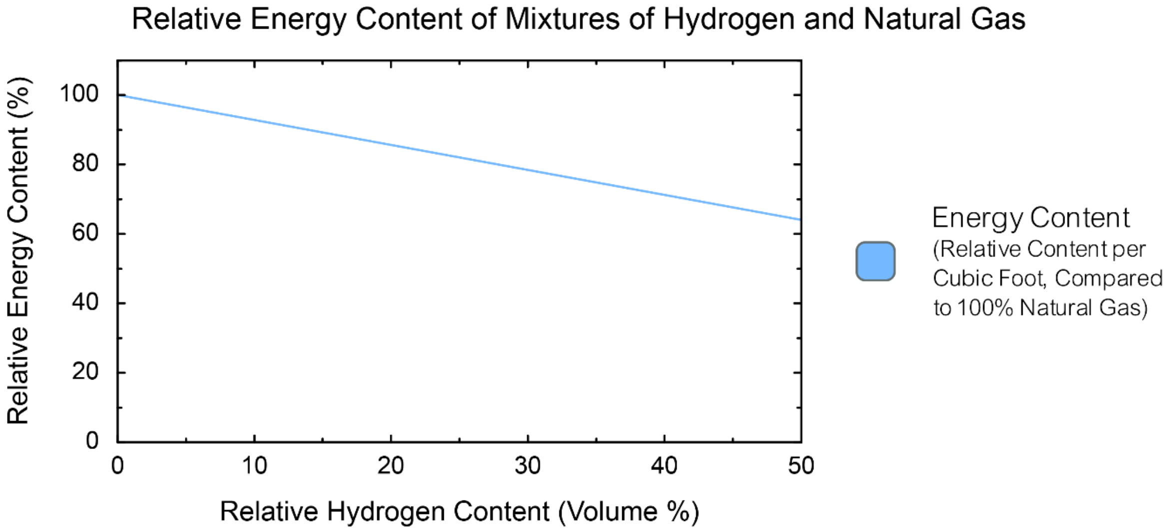

Figure VI-4: Impact of mixing hydrogen on volumetric energy density of hydrogen-natural gas mixtures. Gas pressure is assumed to remain constant.

As a result of the sharp declines in volumetric energy density at increasing hydrogen fraction, blending hydrogen would require more gas volume to deliver the energy flow of pure natural gas. Pushing these increased volumes through a heating system or gas stove would require a higher gas flow rate and hence higher pressures in the distribution system. These increased pressures would exacerbate possible hydrogen leakages, because data published by the California Public Utilities Commission show that gas leak rates are directly proportional to pressure.[282]

As we have discussed in Chapter III (Figure III-3) and in Section a. of this chapter, hydrogen leaks have a climate impact. Such leaks can be significant if hydrogen is distributed in the natural gas system. For context, leaks in the transmission and distribution system account for about one sixth of natural gas leakage.[283] If the analogous hydrogen leakage rate is 4 times that of natural gas,[284] this would mean that on the order of 2% of hydrogen would leak. This does not include leaks at the point of use, such as cooking stoves or gas furnaces. Because hydrogen have only about 27% the energy density per unit volume, a larger volume of gas per unit time would have to be pumped through the gas pipelines to maintain the same rate of energy flow,[285] creating the possibility of even higher leak rates.

Hydrogen blending is being proposed as a method to reduce greenhouse gas emissions, but the actual emissions benefits of hydrogen blending are relatively marginal. This point is illustrated by Figure VI-5, which shows the calculated emissions intensity for blending grey, blue or green hydrogen with natural gas. The calculation assumes a hydrogen leakage rate of 1.86, which is four times the estimate of leakage in the pipeline part of the natural gas system;[286] hydrogen leaks at the points of production and use have not been included in Figure VI-5. In any case, the density and 20-year global warming potential of hydrogen are much smaller than those of natural gas and because most of the energy still comes from

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[282] Penchev *et al.* 2022, Table 1, page 12

[283] Alvarez *et al.* 2018, Table 1

[284] Penchev *et al.* 2022, page 24

[285] Penchev *et al.* 2022

[286] The natural gas pipeline leakage rate of 0.47% is from Alvarez et al. 2018; the estimate of hydrogen leakage at four times the natural gas leakage is from Penchev at al. 2022.

natural gas. Leaks and CO_2 due to natural gas dominate the total warming impact. Hydrogen leaks are just 1.2% of the warming impact in our estimates and would remain a small fraction even if leaks were a few times larger; in other words, the results in Figure VI-5 are not sensitive to assumptions about hydrogen leaks. This picture could change if the fraction of hydrogen increases well above 20% in existing infrastructure or if differentially greater leaking of hydrogen relative to natural gas occurs. Another important caveat is that the emissions impact of blended hydrogen and natural gas does not take into account the possibility of faster deterioration of the pipes when blending hydrogen. In this case, both natural gas and hydrogen leaks would be greater.

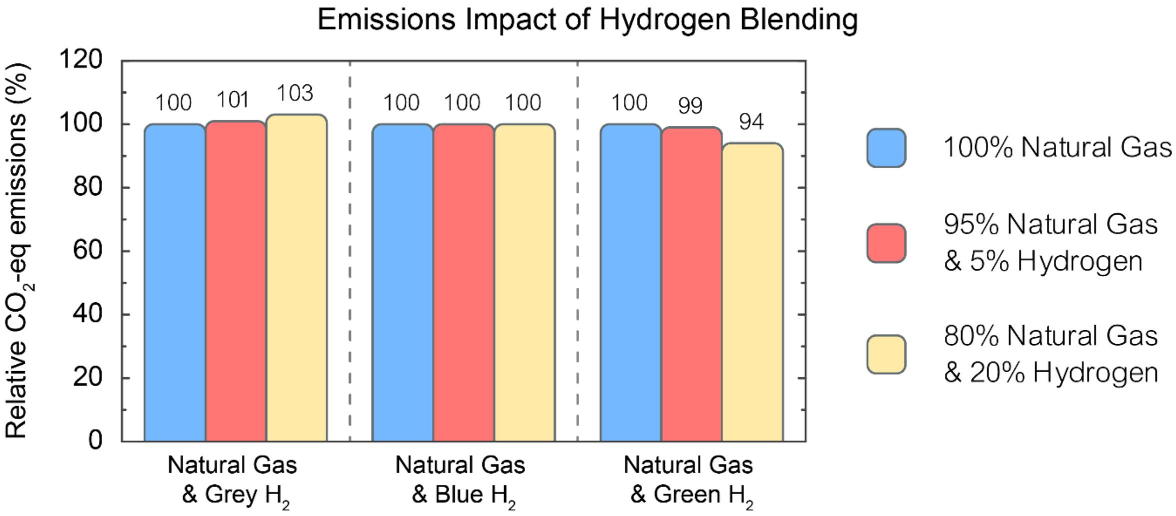

Figure VI-5: Relative greenhouse gas emissions for one million Btu of delivered energy for natural gas alone and natural gas blended with 5% and 20% hydrogen by volume – for grey, blue, and green hydrogen. Absolute emissions for natural gas = 96.3 kg CO_2/million Btu
Source: IEER calculations, based on standard emission factors, and hydrogen production emissions as estimated in Chapter IV (based on the Argonne National Laboratory GREET model) and 2.7% natural gas leaks.

A striking result of the analysis is that even at 20% hydrogen blending, greenhouse gas emissions are reduced by only 6% if green hydrogen is used. Greenhouse gas emissions remain about the same (to the nearest 1%), independent of hydrogen blending volume in the case of blue hydrogen. Emissions actually rise if natural gas is blended with grey hydrogen.

The above analysis uses 2.7% natural gas leaks. Since the Biden administration as well as many corporations have set goals for reducing natural gas leaks, we performed a sensitivity check. If the natural gas leak rate of falls to 1% (with a correspondingly lower hydrogen leak rate), overall emissions would fall because in all cases the main source of energy and the main source of emissions is from natural gas burning followed by natural gas leaks (in CO_2-eq terms). But the emissions for grey and blue hydrogen actually rise relative to natural gas alone. The following climate conclusions can be drawn from the analysis:

- Blending grey hydrogen with natural gas makes the warming impact of the mix worse than using natural gas alone;
- Blending blue hydrogen with natural gas makes no difference to the warming impact of the mix relative to natural gas;

- Blending green hydrogen with natural gas makes reduces the warming impact slightly – by about 1.4% with a 5% blend and by 6.3% with a 20% blend;
- Reducing natural gas leaks makes the relative emissions impact of grey hydrogen worse and could convert blue hydrogen from no benefit to an increase of emissions relative to natural gas alone.

The degradation of natural gas distribution infrastructure must be added to these marginal to negative climate impact of hydrogen blending. Penchev et al. (2022) note that hydrogen can penetrate and embrittle certain types of steel and degrade medium-density polyethylene (MDPE) gas pipes. This degradation could lead to increased gas leakages if gas distribution infrastructure is not upgraded to resist the detrimental effects of hydrogen. Such leakage would further diminish the climate benefits of using hydrogen. Furthermore, leakages can create serious safety hazards if highly flammable hydrogen gas leaks and accumulates in closed-off areas.

To summarize, blending hydrogen into natural gas creates the potential for increased NO_x pollution, hydrogen leakage, and infrastructure degradation, while producing relatively marginal emissions reductions, if any. The main impact of such a policy would likely be to entrench natural gas use and possibly to degrade the safety of the natural gas system.

The above considerations apply to blending in general. We now consider blending in residential applications and for peaking electricity generation using gas turbines.

i. Blending for residential applications

In residential settings, hydrogen could substitute natural gas for cooking, space heating, and water heating in homes with natural gas connections. In this setting, hydrogen is usually presented as a method to reduce greenhouse gas emissions without making any changes to homes. As discussed above, this is only true when using hydrogen that is blended with natural gas at less than 20% by volume. At higher hydrogen proportions, both pipes and appliances would need to be changed to ones that are specifically designed to accommodate hydrogen. At lower hydrogen mixing ratios, there is a risk of increased NO_x pollution from stoves and heaters due to the increased flame temperature of hydrogen-fed systems.[287] However, not much experimental information appears to be available on this risk of indoor air pollution. Beyond the possibility of indoor air pollution, there are other reasons why heating and cooking with hydrogen is undesirable. Many of these are summarized in a 2022 article,[288] which compiles 32 independent studies. Notably, the author excluded industry-funded research papers and found that no independently funded research supports the idea of substituting natural gas like-for-like by hydrogen. The main reasons are that widespread hydrogen distribution would require extensive replacement or refurbishing of the existing gas pipeline network and heating homes with hydrogen is expensive at both a systems and consumer level. A follow-up study reached similar conclusions.[289] Furthermore, hydrogen heating has a high environmental impact,[290] and moreover heating homes with hydrogen is inefficient. **It would take almost 5 times more electricity to heat a home with 100%**

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[287] Leicher *et al.* 2022 and Slorach and Stamford 2021

[288] Rosenow 2022

[289] Rosenow 2023

[290] Slorach and Stamford 2021

electrolytic green hydrogen than with an efficient heat pump.[291] In addition, electrifying stoves instead of burning hydrogen would eliminate indoor air pollution due to gas burning as an added benefit.[292]

There are also environmental justice issues with adding hydrogen to natural gas for residential applications. Middle- and upper-income homeowners with gas heating are likely to take advantage of the various federal and state incentives to electrify their homes for economic and/or health reasons. The risk of low-income homeowners and especially low-income renters being stranded on a natural gas system are already significant. As the proportion of homes using natural gas falls, the costs of paying for the distribution system would fall on a diminishing number of households, causing gas rates to rise. Rates when natural gas customers decline to a small fraction of the present level could skyrocket from $10 or $15 per million Btu to $100 per million Btu or more.[293] Adding hydrogen to natural gas would exacerbate the cost problem, add safety risks, and at best, perpetuate indoor air pollution risks from burning gas or at worst aggravate them.

All in all, the decarbonization of buildings is a vast topic. Using hydrogen in this context is risky, costly, and environmentally and economically unjust. Blending hydrogen would have little or no climate benefit. Consequently, decarbonizing buildings through electrification, improved insulation and other methods is preferable from every point of view.[294]

ii. Blending hydrogen with natural gas for peaking power production

Energy and environmental justice concerns also arise when burning hydrogen in electricity-generating gas turbines; the location of these power plants correlates with historical redlining, and places elevated air pollution burdens on marginalized communities.[295] These burdens can be increased when feeding existing gas turbines with a blend of hydrogen and natural gas, because using this blend causes increased flame temperatures that may increase NO_x emissions up to 7 times.[296] Such NO_x emissions will likely be less of an issue for new turbines that are designed to burn hydrogen and can be engineered to minimize air pollution.[297]

Besides air pollution, burning hydrogen is also generally inefficient. The most efficient natural gas plants are combined-cycle power plants: they burn natural gas in a gas turbine and use the hot exhaust gas to make steam that drives a steam turbine. The gas and steam turbines give it its name: “combined cycle”. While typical efficiencies of combined cycle power plants are in the 50% to 60% range, they can reach around 64% efficiency.[298] However, making hydrogen entails losses – typically only about 70% of the

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[291] A home with 50 million Btu per year natural gas use would require about the same amount of hydrogen, which would take about 23 MWh of electricity to produce (at 47 MWh per metric ton plus 10% to account for delivery energy and losses). The electricity requirements (assuming 90% natural gas heating efficiency) would be about 4.7 MWh, including 6% transmission and distribution losses, and heat pump coefficient of performance = 3).

[292] Lebel *et al.* 2022

[293] Makhijani *et al.* 2023

[294] While electrification is generally the preferred approach, other options such as seasonal thermal storage of renewable energy, including solar thermal energy and solar electricity that might otherwise be curtailed in autumn, are also available. See for instance the thermal storage system used by the Drake Landing Solar Community in Alberta, Canada at https://www.dlsc.ca/how.htm

[295] Cushing *et al.* 2022 and Krieger *et al.* 2016

[296] Cellek and Pınarbaşı 2018

[297] Funke *et al.* 2021 and Haj Ayed *et al.* 2015

[298] Mitsubishi Power 2022

primary energy (natural gas or renewable energy) is stored in the hydrogen fuel. Thus, even at the high end of efficiencies, the overall efficiency would be about 45%.

Notably, using combined-cycle plants is not an option for peaking power production. Peaking refers to rapidly producing electricity at times of high demand, which occurs sporadically. Peaking plants therefore operate only a few percent of the of the hours in the year and need to be rapidly turned on and off when needed. Consequently, peaking natural gas power plants have only gas turbines, which at the high end operate just above 40% efficiency.[299] When the losses involved in hydrogen production are taken into account, the efficiency of peaking generation would be well under 30%.

Using hydrogen for Figure VI-6 shows a comparison of the cost of natural gas peaking generation with natural gas + 25% green hydrogen used in a gas turbine, and solar plus battery in a fully renewable system. The costs are for 2023 as estimated by the Wall Street firm, Lazard, which publishes periodic updates of levelized costs of energy generation and storage.

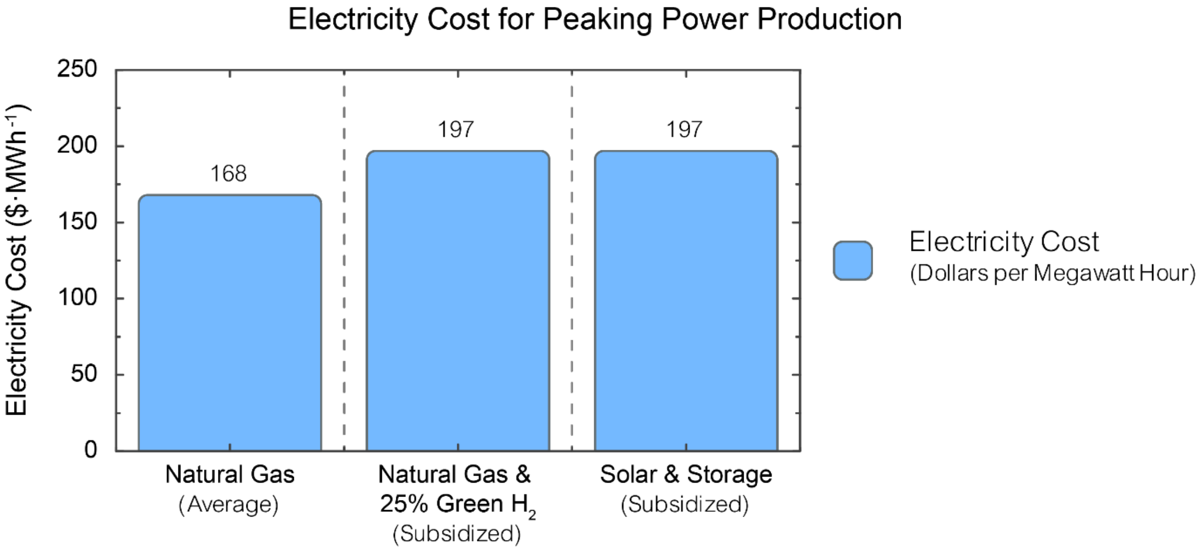

Figure VI-6: Comparing the cost of three systems of peaking generation. Source: Lazard 2023, Slides 23 and 33.

Thus a 25% hydrogen blend with natural gas used in a turbine would cost about the same as utility-scale solar plus battery storage. The latter of these options would have zero emissions, whereas the hydrogen blend would have more than 90% of its energy be supplied by natural gas, such that more than 90% of the greenhouse gas emissions would remain. The above considerations do not factor in the increased cost or the potential for degradation of the natural gas infrastructure when hydrogen is added to it.

Using hydrogen also increases the water requirements of electricity generation because hydrogen production requires a substantial amount of water as discussed in Chapter III.

In short, using hydrogen blends in existing turbines will likely increase air pollution, is less efficient than using renewable electricity directly, and uses large amounts of water. There is minimal climate benefit if green hydrogen is used, no benefit or negative impact of blue and grey hydrogen blending respectively.

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[299] GE 2023

Although these considerations disfavor the combustion of blends of natural gas and hydrogen, using pure hydrogen has some potential applications in power production if 100% hydrogen is used as a fuel. This application is discussed in the next section.

iii. Using 100% hydrogen for peaking power generation

Green or pink hydrogen can be used for peaking power generation with zero emissions (except for any emissions associated with making the capital equipment, which applies to all energy sources until the energy system is decarbonized). If this power is produced in fuel cells, it will be emissions-free. In addition, it could replace gas-fired peaker plants, thus addressing the environmental justice issues of air pollution and adverse health consequences that are associated with these plants. When replacing peaker plants with fuel cells, the water created in the course of hydrogen production can be recovered as well.

We consider two aspects of this peaking power generation issue in this chapter:

1. Opportunity cost of using hydrogen instead of solar energy plus battery storage for peaking power production;[300]
2. Long-term (beyond about 2030) use of green hydrogen for peaking power production and possibly other power applications.

The issues are most easily illustrated by considering the replacement of a typical peaking power gas turbine with zero emission generation: about 50 megawatts capacity, operating at 10% capacity factor and generating about 44,000 MWh per year (all numbers rounded).

Peaking generation involves only short-term storage. This means using most or all of the stored energy within a few days and often on the same day, which is typical of peaking power production

It is generally recognized that short-term storage alone cannot economically address all the variability of wind and solar power. Hydrogen can also be used as a long-duration energy storage medium, as discussed in the previous chapter. There are other forms of long-duration energy storage, including compressed air storage used a complements or substitutes for hydrogen.

Peaking generation in the short-term (up to ~2030)

Both green hydrogen produced with solar energy and solar energy plus battery can provide adequate peaking generation in a wide variety of situations. The roundtrip efficiency of utility-scale lithium-ion battery storage (charging from solar generation and discharging during peak demand) is about 86%.[301] If the solar energy is used to make hydrogen and that hydrogen is used in high efficiency fuel cells, the roundtrip efficiency is about 50%. Thus, much more solar capacity (45 MW) would be needed to replace the gas turbine with green hydrogen than using the solar energy coupled with battery storage (about 26 MW) – see Figure VI-7.

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[300] Storage for peaking power production is short-term battery storage.

[301] PNNL 2020. A range of efficiencies is cited in the literature. The DOE review of grid electricity storage cited here uses a middle of the range efficiency of 86%, which is also used in this report.

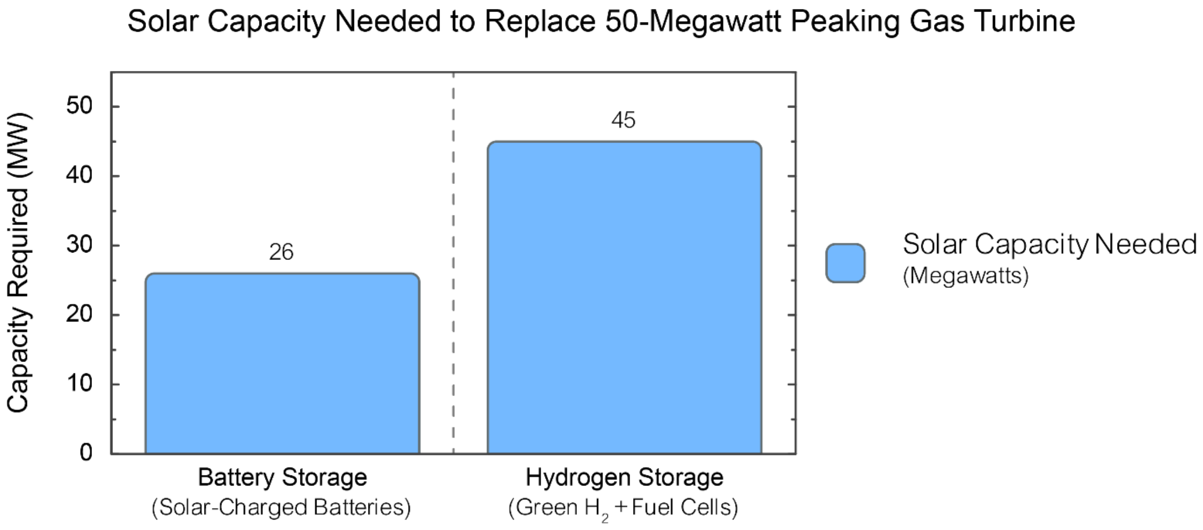

Figure VI-7: Solar generation capacity needed to replace a 50 MW peaking gas turbine with a solar + battery system or a green hydrogen + fuel cell system.
Notes: 1. Gas turbine generation about 44,000 MW/year – about 10% capacity factor.
2. Assumed solar capacity factor: 22%

Viewed in another way, solar generation needed to make hydrogen for the fuel system could be used in with a battery storage system to replace all the gas turbine generation and have enough electricity left over to convert about 10,000 homes from natural gas heating and cooking to efficient electric heating and cooking, eliminating about 47,000 metric tons of CO_2-eq emissions per year as well as in addition to reducing indoor air pollution. The exact comparison would depend on location and insolation, but the general conclusion that it is more efficient and climate friendly to electrify home heating with renewable electricity sources would apply since it is basically an expression of the relative efficiency of the two systems.

Peaking generation in the longer-term (beyond ~2030)

In the longer term, as most households are electrified and solar and wind generation constitute a large fraction of generation (40% to 50% or more), the above picture would change. That change would arise from a combination of factors. In most places, peaks of demand relative to supply[302] would occur in the winter, likely during the night; in some places with very mild winters summer early evening peaks may still dominate. Demand in the spring and fall seasons would continue to be significantly lower than the peak seasons This seasonal mismatch between energy supply and demand would mean large surpluses of renewable electricity in those seasons. As a consequence, this electricity has to be curtailed or stored seasonally. While long-duration batteries are being developed, the goal of these batteries is to extend the time from a few hours to a few days of storage. In general, batteries are unsuitable for seasonal storage for several reasons; major factors include cost and scale of storage needed.

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[302] In a system with large amounts of solar and wind complemented by storage, the most stressed times for supply are not necessarily the times of highest load; rather they would be times of high load relative to variable supply and the state of storage systems.

There are several approaches to seasonal storage that could absorb seasonal solar and wind energy surpluses for useful purposes,[303] including:

- Compressed air storage;
- Thermal storage in insulated cells underground to be recovered for cooling in the summer and heating in the winter;
- Hydrogen, for a variety of applications.

Given vigilance in keeping leaks minimal, using seasonal renewable electricity surpluses to make green hydrogen would not be in conflict with other direct uses of renewable electricity. It would also be low-cost, since the electricity, the main cost of electrolytic hydrogen production,[304] would be essentially free. The Biden administration has set a goal of a decarbonized electricity system by 2035, which implies a very swift ramp up of solar and wind; they are anticipated to be the main new additions to electricity generation capacity from primary energy sources.[305] As a result, green hydrogen used in fuel cells could emerge as a useful approach to using seasonal surpluses of solar and wind energy to reduce overall primary energy requirements by roughly 2030 – earlier in some areas and later in others depending on the pace of deployment. Equally important, optimizing the various seasonal storage options, notably the three listed above, would minimize energy waste (losses due to curtailment), lower cost, and enable the filling of gaps in supply at times of high relative demand that are too expensive for batteries to fill. Finally, green hydrogen produced could also be used in industry for combined heat and power generation – a major use of natural gas in industry today.

Producing green hydrogen with electricity that would otherwise be curtailed will necessarily be an intermittent operation. It is therefore important to choose an electrolyzer technology that can safely operate in an intermittent mode with frequent starts and stops. These criteria favor proton-exchange membrane and anion-exchange membrane electrolyzers. However even in these cases intermittent operation can drastically accelerate degradation, due to chemical reactions that happen while turning them off and back on. The electrochemical community is actively researching methods to slow down this degradation and, consequently, prolong the lifetime of electrolyzers.[306] Such research is crucial to enable electrolyzers to respond to varying renewable energy supplies at scale.

In contrast, intermittent operation of alkaline electrolyzers can pose serious safety hazards due to the risk of the electrolyzer forming explosive water-gas mixtures. Furthermore, alternative high-temperature fuel cells such as molten carbonate and solid oxide fuel cells have longer startup times and are therefore less favorable for intermittent operations as well (see Fuel Cell section below).

Roughly 20 million metric tons of hydrogen could be produced in the long-term from seasonal electricity surpluses in an economy in which wind and solar and the predominant primary sources and two-thirds of the curtailable renewable electricity were used for hydrogen production as a long-duration storage medium.[307] What fraction of curtailable electricity is used for hydrogen compared to other long-duration

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[303] Makhijani *et al.* 2024 (forthcoming)

[304] James *et al.* 2023

[305] NREL 2022c

[306] Kojima et al. 2023

[307] Modeling in Makhijani 2016 indicates that about 25% of electricity in a fully renewable, solar and wind electricity system with a small amount of hydropower (less than 2%) would be in the form of surpluses that would be curtailed. This estimate may be on the high side since Maryland was modeled as an autarkic electricity system

storage methods like compressed air storage, pumped storage (hydropower), seasonal thermal storage or very long duration batteries is difficult to estimate at the present time.

Fuel cells – a brief technical overview

Much of the utility of hydrogen in the energy transition centers on its potential role as an energy carrier: it can be produced via electrolysis using renewable energy, stored, and used later in a variety of applications. Various durations and scales of storage are possible, potentially making hydrogen a flexible and valuable tool in the energy transition – provided it is green hydrogen (see Chapter IV) and leaks are kept low.

Many of the important potential uses of hydrogen involve the use of fuel cells, which convert chemically stored energy from hydrogen into electricity. As such, these devices essentially operate in the reverse manner that electrolyzers do. In a sense, electrolyzers and fuel cells operate on a concept similar to batteries: electrolyzers are the energy storage aspect – like charging the battery; fuel cells are the energy use aspect – like discharging the battery and using the stored energy. A central difference is that the chemical energy produced by electrolysis in the form on hydrogen is sent out of the electrolyzer – to be used on site, transported to other locations, or stored for future use. Another major difference is that hydrogen can be transported to another location for use, whereas with a battery the recovery of energy occurs at the same place as the storage – that is, at the site where the battery is located.

Most fuel cells are constructed in a manner that resembles electrolyzers, as is visualized in Figure VI-8; See Figure IV-2 in Chapter IV for comparison.

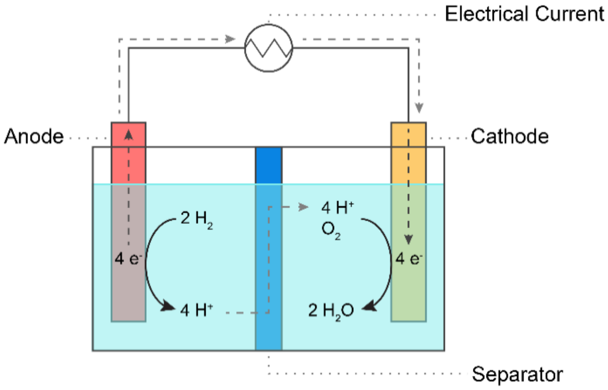

Figure VI-8: Schematic depiction of a fuel cell.

Like electrolyzers, fuel cells contain an anode and a cathode. These electrodes are supplied with hydrogen and oxygen gas (gas inlet ports not depicted in Figure VI-8). The anode converts hydrogen (H_2) into protons (H^+) and electrons (e^-). The electrons travel through an external circuit towards the cathode, where they combine with the protons and oxygen to form water. Thus, the overall reaction in a hydrogen-fed fuel cell is:

$$2\ H_2 + O_2 \rightarrow 2\ H_2O$$

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for simplicity. A total generation 7 billion MWh in 2050 is indicated for a highly electrified electricity system whose supply is predominantly solar and wind. Assuming 20% (1.4 billion MWh) would be curtailed and available for long-duration storage and that two-thirds is used for hydrogen, about 20 million metric tons of electrolytic green hydrogen production could be produced.

This reaction releases energy in the form of electricity. The theoretical voltage of this electricity is 1.23 V: a slightly lower voltage than an AA battery. However, this voltage is often lower due to internal energy losses that are similar to those occurring in electrolyzers. Such losses give rise to an 'overpotential' that reduces the output voltage of the fuel cell. The overpotential determines the overall efficiency of a fuel cell, which is given by:

$$Efficiency = \frac{1.23 - overpotential}{1.23} \times 100\% = \frac{fuel\ cell\ operating\ voltage}{1.23} \times 100\%$$

Many hydrogen-powered fuel cells will operate between 50% and 70% efficiency, thus producing approximately 0.6 V to 0.9 V.[308] These voltages are much lower than the high voltages required for grid-level electricity production or powering vehicles, but the outputs voltage can be increased by connecting multiple fuel cells in series. If this is done, the voltage is proportional by the number of fuel cells that are connected.

Recall from Chapter IV that a voltage greater than 1.23 volts is needed for the electrolyzer when hydrogen is produced from water, resulting in energy loss. These losses compound on the losses that occur when using the hydrogen to create electricity in a fuel cell. It is the same with batteries where losses occur during charging and discharging. In the case of batteries, the "roundtrip efficiency" that can range from 40% to 90%, with the lower figure applying to certain long-duration storage technologies. In the case of hydrogen, the roundtrip efficiency range is between 30% and 60%. Both estimates exclude leakage (or charge or hydrogen).

There are many types of fuel cells, some of which can be fed with other fuels than hydrogen. The five most important fuel cells for use with hydrogen will be described below, and alternative feedstocks will be noted when applicable. These fuel cells are depicted schematically in Figure VI-9.

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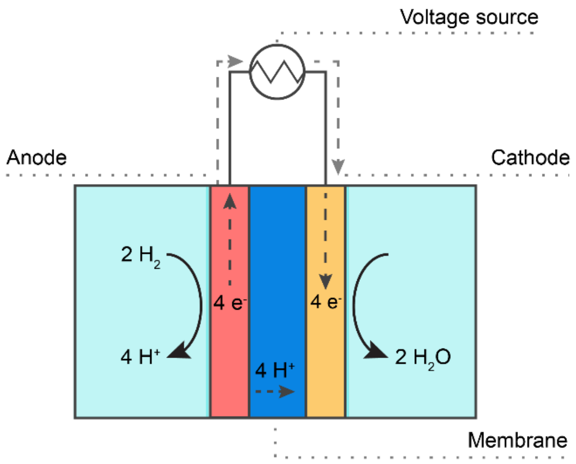
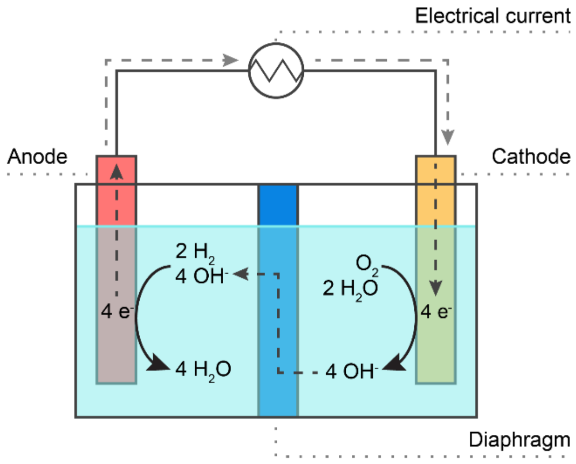
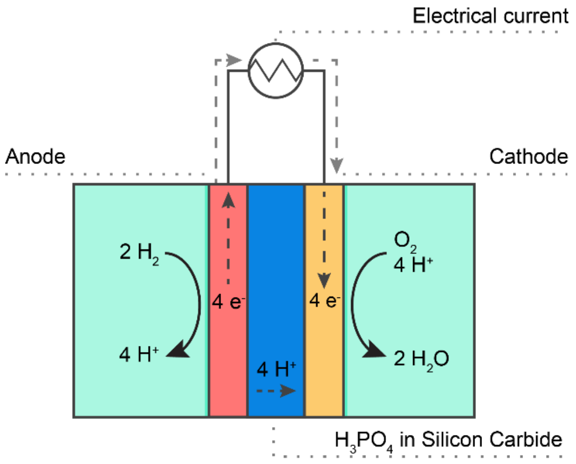
[308] Some fuel cells can operate at higher efficiencies by capturing and using excess heat that the fuel generates. This type of operation is called "combined heat and power" (CHP) and can push overall fuel cell efficiencies to 90%. (Nguyen and Shabani 2020). Although capturing heat increases overall efficiency, capturing heat does not increase the output voltage of an electrolyzer.



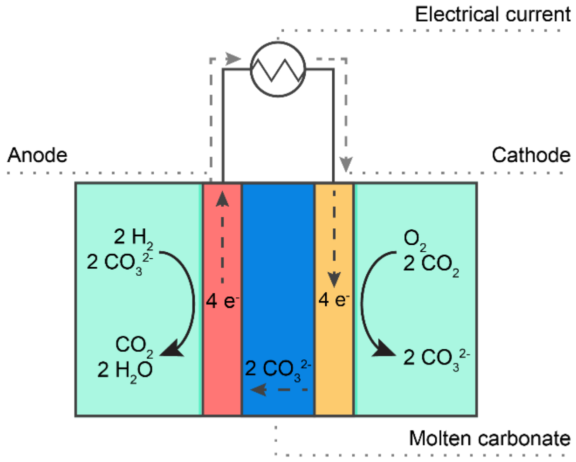
Proton-Exchange Membrane



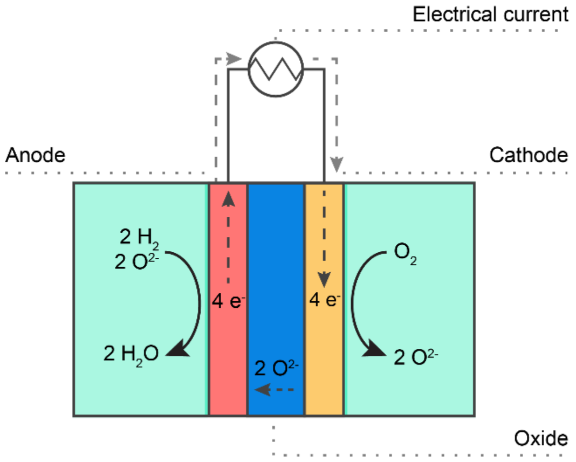
Alkaline



Phosphoric Acid



Molten Carbonate



Solid Oxide

Figure VI-9: The five most common types of fuel cells.

The first of these fuel cells is the proton-exchange membrane fuel cell, which is essentially a reverse proton-exchange membrane electrolyzer because its cathode and anode are separated by a thin membrane that conducts protons. The catalysts on both the cathode and anode side are typically platinum-based. This fuel cell type operates at temperatures between 40 °C (104 °F) and 80 °C,[309] at efficiencies between 50% and 70%.[310] Proton-exchange membrane fuel cells take less than a minute to start up and are highly versatile: depending on how many fuel cells are connected, they can be deployed on a scale between a watt and 0.5 megawatt.[311] These devices are relatively sensitive to contaminations in the gas feed, but this is only a concern when using fossil-derived hydrogen to drive the fuel cell; these feedstocks can contain carbon monoxide or sulfur contamination.

The second type of fuel cells is the alkaline fuel cell, which operates like a reverse alkaline electrolyzer. Consequently, it uses platinum- or nickel-based cathode and anode catalysts, a diaphragm separator, and a highly concentrated potassium hydroxide solution that transports hydroxide ions (OH^-) from the cathode to the anode. Because the device operates under alkaline conditions, its reactions are:

Cathode: $O_2 + 2\ H_2O + 4\ e^- \rightarrow 4\ OH^-$
Anode: $2\ H_2 + 4\ OH^- \rightarrow 4\ H_2O + 4\ e^-$
Overall: $2\ H_2 + O_2 \rightarrow 2\ H_2O$

Alkaline fuel cells operate between 20 °C (68 °F) and 250 °C (482 °F), at 60% to 70% efficiency, and with a startup time below 1 minute.[312] They are highly sensitive to carbon dioxide, which precipitates in the potassium hydroxide solution to form potassium carbonate. This sensitivity means that the cathode can only be supplied with pure oxygen or with air from which carbon dioxide has been scrubbed; such precautions add cost and complexity to the fuel cell system.[313]

Another fuel cell type is the phosphoric acid fuel cell, which uses highly concentrated liquid phosphoric acid (H_3PO_4) to transport protons from the anode to the cathode. The phosphoric acid is contained in a porous, solid silicon carbide (SiC) matrix, which provides stability to the fuel cell.[314] These devices operate between 150 °C (302 °F) and 220 °C (428 °F) to overcome the limited conductivity of phosphoric acid at lower temperatures.[315] Their efficiency sits around 55%,[316] but some of the produced heat can be extracted to increase the overall efficiency to 80%.[317] A phosphoric acid fuel cell's cathode and anode catalysts are platinum-based, and their startup time is higher than that of proton-exchange membrane and alkaline fuel cells. This type of fuel cell is less sensitive to carbon monoxide poisoning, which makes it more suitable for use with blue and grey hydrogen that may contain trace amounts of this gas.

Another contamination-resistant fuel cell is the molten carbonate fuel cell, which can even be fed with carbon monoxide or methane.[318] The reactions in this fuel cell are:

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[309] Acar *et al.* 2022
[310] Singla *et al.* 2017
[311] Abdelkareem *et al.* 2021
[312] Acar *et al.* 2022 and TÜV NORD GROUP 2023
[313] Acar *et al.* 2022
[314] O'Hayre *et al.* 2016
[315] Acar *et al.* 2022
[316] Singla *et al.* 2021
[317] Acar *et al.* 2022
[318] Singla *et al.* 2021 and TÜV NORD GROUP 2023

Cathode: $O_2 + 2\ CO_2 + 4\ e^- \rightarrow 2\ CO_3^{2-}$
Anode: $2\ H_2 + 2\ CO_3^{2-} \rightarrow 2\ H_2O + 2\ CO_2 + 4e^-$
Overall: $2\ H_2 + O_2 \rightarrow 2\ H_2O$

In these reactions, carbonate (CO_3^{2-}) ions are produced using carbon dioxide, which travel from the cathode to the anode through a molten lithium or potassium carbonate that is contained in a lithium aluminate ($LiAlO_2$) matrix.[319] Because it takes a very high temperature to melt lithium and potassium carbonate, molten carbonate fuel cells operate between 550 °C (1022 °F) and 700 °C (1292 °F). Building up this temperature takes some time, which is why this type of fuel cell has a startup time of 10 minutes. The high operating temperatures have both advantages and disadvantages. Advantages include the use of affordable nickel-based cathode and anode catalysts and the ability to cogenerate heat to increase its efficiency from 55% to 80%.[320] Drawbacks include the highly corrosive nature of high-temperature carbonate salts and hydrogen and oxygen gases, which pose constraints on the materials that can be used to build molten carbonate fuel cells. Furthermore, these fuel cells have a relatively low power density, such that more fuel cells are required to achieve a given power output.

The fifth and final fuel cell type is the solid oxide fuel cell, which operates like a reverse solid oxide electrolyzer. As such, it operates between 600 °C (1112 °F) and 1100 °C (2012 °F), has an efficiency of 60%-65%, uses an yttria-stabilized zirconia (YSZ) solid oxide, and employs lanthanum strontium manganite and nickel-based YSZ catalysts.[321] This fuel cell can handle carbon monoxide and methane inputs as well, but when operated with hydrogen, its reactions are as follows:

Cathode: $O_2 + 4\ e^- \rightarrow 2\ O^{2-}$
Anode: $4\ H^+ + 2\ O^{2-} \rightarrow 2\ H_2O + 4\ e^-$
Overall: $2\ H_2 + O_2 \rightarrow 2\ H_2O$

Its startup time is relatively long (approximately 1 hour), which is why a solid oxide fuel cell would usually be used for constant operation. Despite the highly corrosive high-temperature conditions that limit which materials can be used, this type of fuel cell can be used to co-generate heat, does not require noble metal catalysts, and has long device lifetimes of up to 80,000 hours.[322]

d. Transit buses

Because of its energy content, hydrogen has also been explored for use as transportation fuel, specifically for use in transit buses and class 8 trucks. These applications will be discussed in the present and following section of the report, respectively.

Using hydrogen as transportation fuel has important potential benefits. First of all, hydrogen can eliminate air pollution at the point of use if fuel cells replace diesel or other fossil fuels. If this were done, neighbors, bicyclists, and pedestrians would no longer have to breathe in diesel fumes, which are created in hazardous amounts in many communities. Furthermore, replacing diesel with hydrogen could reduce greenhouse gas emissions, thus making hydrogen a potential solution to decarbonize transportation.

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[319] Acar *et al.* 2022
[320] Acar *et al.* 2022
[321] Singla *et al.* 2021
[322] Singla *et al.* 2021

Importantly, the reduced air pollution and greenhouse gas emissions of hydrogen would also be achieved when replacing diesel buses by battery electric buses. Therefore, it is important to compare both battery electric and hydrogen buses when deciding how to decarbonize passenger transportation. The comparison of emissions from battery electric and fuel cell vehicles depends centrally on the greenhouse gas emissions per kilowatt-hour of electricity and per kilogram of hydrogen. Both vary greatly. We have therefore illustrated the range of emissions per mile traveled using these sources:

- Four electricity sources:
    - Average emissions per kWh from electricity generation in Oregon, a low-emissions state;
    - National average emissions per kWh from electricity generation;
    - Average emissions per kWh from electricity generation in West Virginia, a high-emissions state.
    - Solar electricity;
- The following hydrogen sources:
    - Steam methane reforming using methane in natural gas without CCS;
    - Steam methane reforming using methane in natural gas with CCS;
    - Electrolytic hydrogen using electricity sources as above.

The electricity sources are chosen as heuristic illustrations of the variation in emissions from battery vehicles compared to fuel cell vehicles when the hydrogen fuel is made by electrolysis. They do not represent real-world charging situations. Rather, they illustrate greenhouse gas emissions corresponding to a low-emission, a medium-emission, and a high-emission electricity source. Actual emissions depend on the time of charging and the region of the grid that typically supplies the electricity at charging times. Emissions due to hydrogen production using grid electricity would correspond closely to average emissions in that grid region, since electrolyzers would normally operate with high capacity factors.

We compare these emissions estimate with diesel vehicles. In all cases, we take methane leaks from natural gas systems into account, using recent data in the literature and the IPCC6 20-year warming potential for methane (82.5 relative to CO_2). We also take into account methane leaks in the electricity generation system, for the natural gas portion of generation. All methane leaks are calculated at a single national rate based on system leakage of 2.7% of natural gas used.

Finally, for the second part of our analysis, we also account for hydrogen leaks, using a 20-year effective warming potential due to indirect impacts of 33 relative to CO_2. Hydrogen leaks vary greatly depending on the production and transportation methods, as well as on the end use. They tend to be lowest when the hydrogen is produced at the site where it is used. In contrast, hydrogen transported by truck (the typical method of bringing it to fueling stations) could result in leaks large enough to have a climate impact. We use a median leakage estimates for this part of the analysis (Figure III-2).

Though battery electric buses (BEBs) and fuel cell electric buses (FCEBs) buses are relatively new, they have been around long enough to make a comparison possible. When making this comparison, it should be noted that both investment costs and operating costs have been and will continue to be affected by federal and state support, with the former having increased by recent federal legislation, specifically the Infrastructure Investment and Jobs Act and the Inflation Reduction Act. The new support in those laws is also not addressed here.

Despite these complexities, the climate impact is central to considerations for changing from the present diesel-bus-centered transit systems to what are called zero-emission buses. No system is truly zero emissions on a life-cycle basis, since fossil fuels inevitably enter the picture because they are still central to manufacturing, transportation, and electricity production. However, it is still essential to know:

- the relative climate impact of BEBs and FCEBs in absolute terms and relative to present diesel systems and each other;
- whether the climate impact can be made close to zero as the underlying primary energy system is decarbonized;
- the environmental justice impacts in absolute and relative terms.

The Alameda-Contra Costa Transit system in California (AC Transit) has done a side-by-side comparison of five different types of transit buses in actual service – diesel, diesel hybrid, battery-electric, relatively recent fuel cell, and "legacy fuel cell" buses.[323] The National Renewable Energy Laboratory (NREL) has also evaluated several transit systems that have fuel cell buses, as well as conducting three evaluations of electric buses.[324]

The evaluations of FCEBs cited above do not mention a hydrogen source. The AC Transit evaluation mentions a small solar electrolysis system – 65 kilograms per day;[325] however, that is only enough for about two buses; it has a fleet of 36 FCEBs. The remainder of the required hydrogen is supplied by third parties.[326] Since the vast majority of hydrogen in the United States is produced using steam reforming of methane (the cheapest source of hydrogen), the inference, in the absence of a specific mention, is that SMR without CCS is the source of FCEB hydrogen. This is also indicated by a very similar cost of hydrogen across the FCEB evaluations cited above (between $8 and $9 per kilogram).

To analyze the impact of FCEBs and BEBs more explicitly, Figure VI-10 shows the CO_2-equivalent emissions of the BEBs compared to the FCEBs per mile for the electricity and hydrogen sources named above. The operational data for Figure VI-10 are primarily from field evaluations.[327] The impact of hydrogen leaks are considered separately in Figure V-11. As anticipated, climate impacts are highly dependent on the electricity source. For example, the West Virginia electricity case is shown as an example for a coal-intensive electricity supply. In practice, those emissions would not apply almost anywhere in the United States on an annual average basis.[328] The coastal region of the Western Interconnect is more likely to be similar to the "Oregon grid" emissions values since the northwest has a large hydro supply and California has a large solar supply as well as some hydro from the Columbia River region.

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[323] AC Transit 2022

[324] NREL 2021a

[325] AC Transit 2022

[326] AC Transit 2021, page 5 and 7

[327] AC Transit 2022

[328] Specifically, West Virginia is part of the PJM grid that stretches from Chicago to the mid-Atlantic region; the emissions characteristics of the PJM grid, the largest in the United States, are quite close to the national average. But being a large grid, charging-related emissions would depend significantly on the region and the time; thus West Virginia may well have higher emissions for bus-charging than the PJM average, but if charging is at night, nuclear, combined cycle gas, and some hydro and wind would be a larger part of the supply resulting in lower emissions per mile.

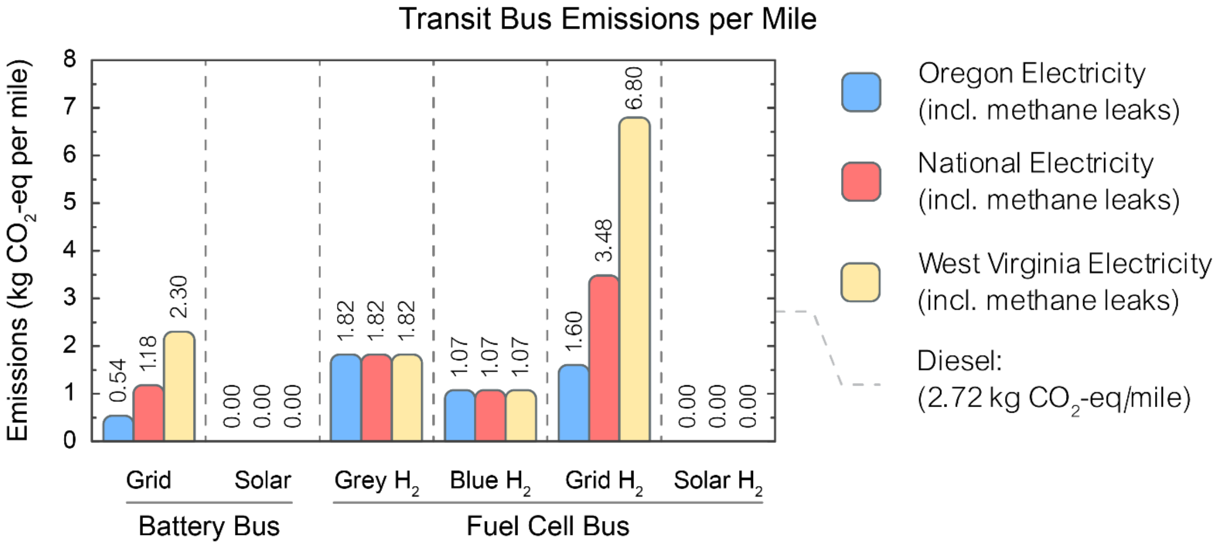

Figure VI-10: CO_2-eq emissions per mile comparison of a battery electric bus (BEB) with a fuel cell electric bus (FCEB) for various fuel sources (lifecycle basis) for transit buses. Diesel bus CO_2 emissions shown for comparison. The "national elec." Is typical of most situations in the United States. The West Virginia electricity case is shown as a heuristic example of a high-coal generating system.

Notes: 1. Electric bus efficiency: 0.46 miles/kWh; FCEB efficiency: 8 miles/kg H_2, based on AC Transit and NREL field evaluation data using the higher end of the experience in various trials (AC Transit 2022).
2. Electrolysis efficiency: 70%: energy requirement: 47.7 kWh/kg H_2. Compression of hydrogen for transport and for fueling is taken into account at 1.9 kWh/kg and 1.87 kWh/kg respectively.
3. Steam methane reforming emissions calculated from Argonne National Laboratory (Figure 2 and Table 4), by adjusting for higher leaks (2.7% v. 1% and 20-year GWP (82.5) v. 100-y GWP (29.8) – both GWPs are from IPCC Sixth Assessment report). CCS-related emissions also adjusted for methane leaks. No mitigation of methane leaks is assumed.
4. Grid emissions are calculated as follows: The total of direct CO_2 emissions due to all fossil fuel generation is divided by the total generation from all sources. Methane leaks at a rate of 2.7% are attributed to the total natural gas use and the 20-year warming potential of 82.5 is applied to obtain the CO_2-equivalent attributable to natural gas generation due to leaks.
5. Solar energy CO_2 equivalent emissions are taken as zero since there are no on-site or process-related emissions. Solar panel production and installation-related emissions are not taken into account, even though true life-cycle assessment would include them. This exclusion was done to maintain comparability to blue and grey hydrogen CO_2-eq emissions, which are taken from the Argonne National Laboratory's GREET model. The GREET model includes upstream fuel-related emissions, notably methane leaks, but does not include emissions associated with capital investment in hydrogen production or CCS.
6. Reference diesel emissions based on 3.99 miles per gallon from AC Transit (2022), Figure 8.

Figure VI-10 shows that, presently, BEBs are superior to fuel cell electric buses in terms of emissions in most scenarios, even when using grid electricity. A notable exception is using hydrogen from steam methane reforming + CCS (blue hydrogen), but this technology is not a reality yet on any scale (there has been one CCS demonstration project for hydrogen where the CO_2 was used for stimulating oil production; see Chapter IV). Further, the Argonne GREET model assumes a 96% efficiency for CCS, which is not borne out in practice across a wide variety of CCS demonstration projects; these projects indicate a capture range of 30 to 80% (rounded).[329] As a first approximation, blue hydrogen FCEBs may be considered typically equivalent to BEBs charged with grid electricity. Given the wide variation in electricity-related emissions and the fact that blue hydrogen is not a commercial reality, the practical comparison must be of BEBs with grey-hydrogen-fueled FCEBs. Further, grid electricity emissions are projected to decline steady until they reach zero by 2035. As a result, BEBs would be clearly superior over the lifetime of the bus.

Without CCS, fuel cell buses using commercial hydrogen steam methane reforming are only somewhat better than diesel buses. When instead considering electrolytic hydrogen, battery buses also emit fewer CO_2-equivalents than fuel cell buses for each electricity grid mix. Notably, the absolute emissions difference between these technologies diminishes for cleaner electricity grid. In fact, when accounting for fully decarbonized solar energy, BEBs or FCEBs both cause zero emissions and are therefore superior to all other cases by a big margin.

This picture changes when we add the climate impact of hydrogen leaks, which are discussed in detail in Chapter III. In this section, we take the plausible low and high leakage estimates in the context of delivering compressed hydrogen by truck and fueling this hydrogen into FCEBs. Table VI-1 shows those estimates for three types of hydrogen, since leaks depend on production method as well.

Table VI-1: High and low estimates of hydrogen leaks for fueling transit buses.

Hydrogen production method	Leak estimate	CO_2-eq/mile
Grey H_2 (Note 3)	7.97%	0.33
Blue H_2 (Note 4)	8.45%	0.35
Electrolytic H_2 (Note 5)	9.93%	0.41

Source: Figure III-2 for leak rates and Ocko and Hamburg 2022 for the global warming potential.
Notes: 1. We use a 20-year global warming potential 33. See Chapter III.
2. Compressed hydrogen transport from the production to the fueling depot is assumed for all production methods.
3. Grey hydrogen leak components are: Production: 0.71%,; compression 0.19%, transportation to fueling depot 1.52%; storage at the depot 4.25%; on-board leaks 1.52%, yielding totals of 7.97%.
4. Blue hydrogen leak components are: Production: 1.22%; the other components are the same as grey H_2, yielding totals of 8.45%.
5. Electrolytic hydrogen leak components are: Production: 2.83%; the other components are the same as grey H_2, yielding totals of 9.93%. Leaks are equal for all electrolytic H_2 since leaks do not depend on the source of electricity.
6. An efficiency of 8 miles per kilogram of H_2 is assumed, consistent the with analysis of FCEBs above to obtain leak rates per mile, which is then translated into CO_2-eq at a GWP of 33.

Figure VI-11 shows the impact of adding the median estimate of hydrogen leaks to the other elements of warming impacts. Note that with addition of leaks, the supposed advantage of blue hydrogen with respect to batteries for transit buses disappears. There is some uncertainty in leak estimates (see Figure III-2 error bars), but the other warming elements are so much higher that the relative merit of the of the different FCEBs remains unchanged.

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[329] IEEFA 2023. The extremely high CCS capture assumption is a significant flaw in the GREET model as of this writing (late 2023).

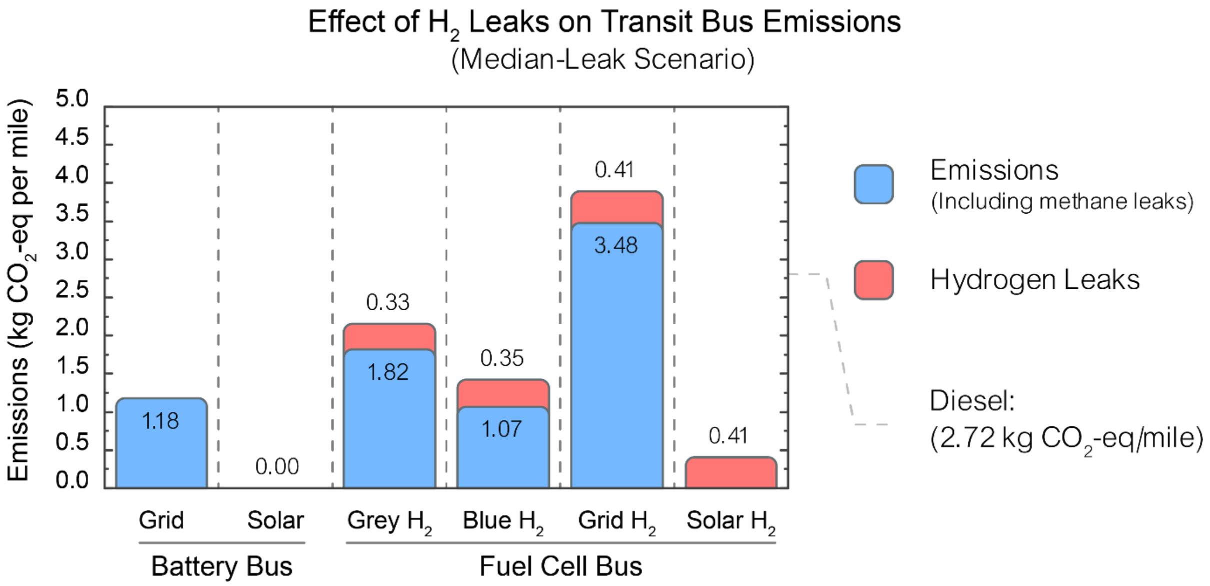

Figure VI-11: Effect of hydrogen leaks on transit bus warming impact. Sources: See notes to Figure VI-9 and Table VI-1 above.

Some aspects of transit bus cost and operating expenses

In addition to emissions, there are multiple other considerations when evaluating battery electric buses and fuel cell electric buses. For example, the AC Transit evaluation cited above showed a $0.91 higher operating cost per mile (including fuel cost) for FCEBs than BEBs before any zero-emission credits were applied. The vast majority of the cost difference (80%) was due to the higher fuel cost for FCEBs. However, BEBs had a shorter range: 180 miles, compared to 300 miles for FCEBs. The relative economics will thus depend on the cost of buses and state and local incentives, and the cost of fueling infrastructure, in addition to the operating costs.

The second concern of range has been a factor historically for Battery Electric Buses (BEBs). For instance, the U.S. electric bus manufacturer Proterra's first model was a hybrid battery-fuel-cell bus. This bus model has now been discontinued and, nominally, the range issue has been addressed. For instance, Proterra makes the ZX series of battery buses with ranges from 220 to 340 miles of range.[330] The need for range varies by city and route, but an indicative example is the AC Transit case: diesel buses average 250 to 300 miles per day in the AC Transit region in the Bay Area in California. At the upper end of the range of BEBs, there appears to be some margin for loss of range. These are nominal ranges at specified ambient weather and operating conditions. Both BEBs and FCEBs lose range in cold weather, especially below freezing, but BEBs lose a larger fraction than FCEBs.[331] A 10 °F temperature drop increases fuel consumption by between 3.3% and 21% depending on the bus and the baseline ambient temperature. Comparable loss of efficiency for FCEBs is between 5.7% and 12.8%. There is also some loss of range in warm weather, when air-conditioning is needed.[332]

The lower operating cost of BEBs means that additional investments could be made to accommodate the need to maintain range in cold weather. For instance, at 80,000 miles per year, the *added* annual

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[330] Proterra 2023
[331] Henning *et al.* 2019
[332] Henning *et al.* 2019, Table 4 and 5

operating cost of FCEBs relative to BEBs, based on AC Transit data, was about $73,000 per bus. The present value of these added costs over five years, discounted at 3%, is about $333,000 per bus. A 5% discount rate gives a present value of about $315,000. If the weather-related upgrades cost more than, say, $300,000, then fuel cell buses would be more economical; otherwise BEBs would remain lower cost.

An example of additional investments is top up induction charging at stops where many passengers get on and off; this could provide a modest amount of added range. For example, induction charging was installed in Wenatchee, Washington to increase the range of battery buses from 180 to 300 miles.[333] A mix of battery buses and trolley buses powered by overhead wires could also be used. For instance, King County, Washington plans to electrify its public transit in this way, retaining electric trolley buses and adding battery electric buses. Such approaches could overcome range and weather issues, while retaining the efficiency and climate advantages of battery-electric vehicles.

In sum, with the improvements in range and available means to deal with loss of range in cold weather, climate and operating cost considerations would appear to favor electric public transit. The demand for hydrogen in this sector would likely be modest.

i. Opportunity costs of using FCEBs instead of BEBs

Until there is enough solar and wind energy on the grid to enable large amounts of hydrogen production, using solar energy to make hydrogen for buses has an opportunity cost in the short and medium term. This cost stems from an inevitable choice: one can use renewable energy to make hydrogen or one can use it to decarbonize other sectors. This opportunity cost will be explored in the present section.

In the short and medium term, there are many uses that need to be decarbonized and would provide larger climate benefits than using renewable energy to make hydrogen for vehicles where battery use is feasible. To illustrate this point, we compare the use of renewable electricity to make hydrogen for a fuel cell bus while continuing to use natural gas for residential heating (Option 1) with using the same amount of renewable energy to electrify heating in natural gas heated homes while charging electric buses from the grid with average CO_2 emissions (Option 2). This calculation shows the opportunity cost of using electricity for hydrogen buses during a period when there are competing decarbonization needs. Another way of saying it that it provides a way to prioritize decarbonization needs.

Figure VI-12 shows the results of the analysis for buses used for 80,000 miles per year. Using solar energy to make hydrogen for fuel cell buses has about 500 metric tons more emissions per year than charging the bus with national average grid electricity and using the same amount of solar energy for home electrification.

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[333] Hampel 2021

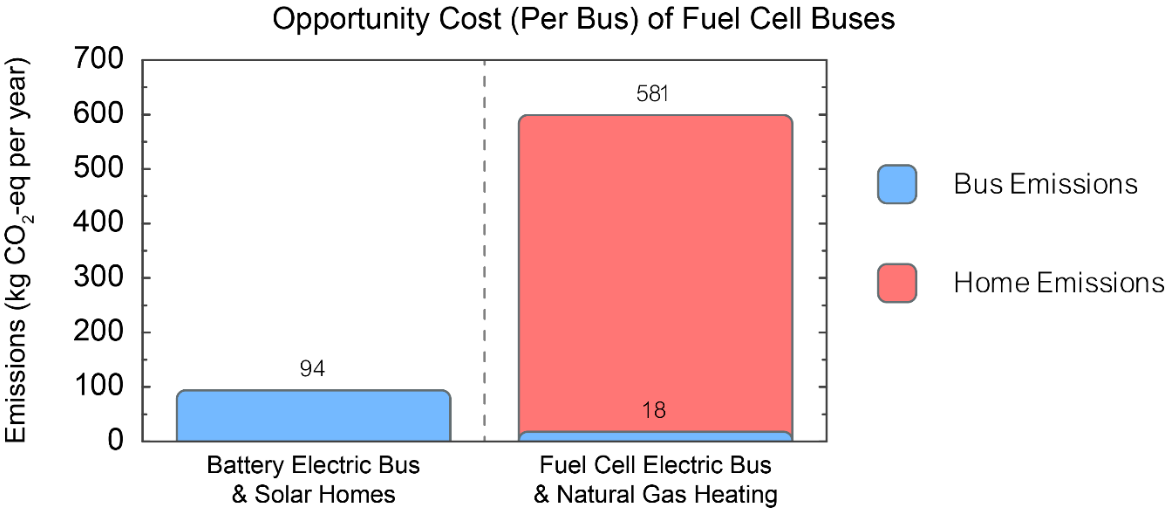

Figure VI-12: Comparison of two options for using solar energy – an FCEB or converting natural gas heated homes. Notes: National average natural gas use per home using natural gas = 81 million Btu.[334] *Number of homes using natural gas heating = 59.2 million.*[335]

In other words, Figure V-12 shows that emissions from a grid-charged bus and homes electrified with renewable energy are about six times lower than using the renewable energy to make green hydrogen for a fuel cell bus and continuing to use natural gas for heating. About 80 homes could be electrified with renewable energy for every bus using hydrogen in fuel cells for 80,000 miles per year.

In addition to these greenhouse gas benefits, there are, other dimensions to the issue that must be considered. Notably, electrifying natural gas homes reduces indoor air pollution (including organic contaminants, nitrogen oxides and carbon monoxide) that causes significant health harm, particularly in low-income households, as many recent studies have documented.[336] At the same time replacing diesel buses with battery buses would reduce air pollution. These would also be achieved with FCEBs. Overall, there are opportunity costs in terms of adverse health outcomes due to indoor air pollution of choosing FCEBs over BEBs.

Charging a battery electric bus with present-day grid electricity implies nitrogen oxide and particulate emissions and in many areas sulfur dioxide emissions as well. Since fossil fuel power plants are located disproportionately in environmental justice and rural communities (or both),[337] *there is a strong argument for giving preference to conversion of natural gas heated homes in those communities so that they can get the benefit from indoor air pollution reduction and at the same time prioritizing conversion of natural gas peaking plants to solar electricity plus battery storage as discussed in the previous section.*

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[334] EIA 2021

[335] Census 2021

[336] A number of publications on indoor air pollution from natural gas are cited in Chapter III of Makhijani et al. 2023. This chapter also specifically has data on the incidence of indoor air pollution, including carbon monoxide, due to cooking stoves in low-income homes in Maryland.

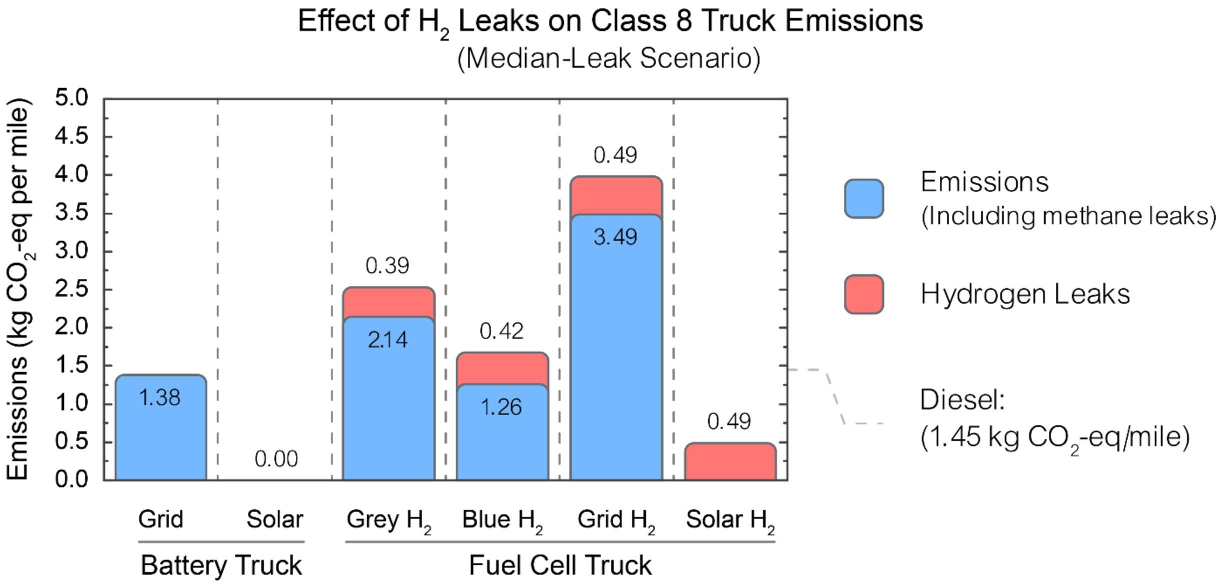
[337] Cushing *et al.* 2022

e. Class 8 trucks

Another potential use case for hydrogen as a fuel is Class 8 trucks. These trucks are the heaviest truck category and are therefore also referred to as heavy-duty trucks. Class 8 trucks come in a variety of designs. The most conducive for fuel cell versions due to range, weather, and operating cycle would be long-haul Class 8 trucks whose 24-hour mileage could run to 500 miles or more, if operated by more than one driver during a single day. Because these trucks are essentially used continuously under these circumstances, charging time becomes a significant issue.

Unlike transit buses, there is not a lot of operating experience with battery electric Class 8 trucks (BE8 truck) or even fuel cell Class 8 trucks. The ones on the road, such as Volvo Class 8 electric trucks have ranges less than 300 miles. Because of this lack of data and to avoid relying on manufacturer claims of future performance in terms of range and fuel efficiency, we have used an Argonne National Laboratory has a prospective evaluation of Class 8 trucks for the year 2025.[338] The study considers different truck types with different duty cycles (especially whether they are used for single or multiple shifts), which we will also consider for this analysis.

Analogous to our analysis for buses, we will first evaluate greenhouse gas emissions for battery and fuel cell trucks. Since the basic pattern is similar to transit buses, we show a summary analysis with national average electricity-related greenhouse gas emissions and median estimates of hydrogen leaks in Figures VI-13. Since Battery-Class truck, Fuel Cell Class 8 truck, and diesel truck efficiency estimates are for the year 2025, the electricity grid estimates for that year, based on the Energy Information Administration’s Annual Energy Outlook have been used.[339] Our analysis is narrowly constrained to greenhouse gas emissions, and therefore ignores differences in fueling/charging time between hydrogen and battery trucks. These times required to ‘fill up’ a truck with either hydrogen or electricity are dependent on on-site charging and fueling infrastructure, and will need to be considered separately when comparing different truck technologies.



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[338] Argonne 2021

[339] EIA2023c

Figure VI-13. Comparative warming impact of Class 8 trucks for projected 2025 fuel efficiencies and grid emissions. Source: Argonne 2021 and EIA 2023c; leak estimates as for transit buses. 20-year global warming potentials used for hydrogen and upstream methane emissions.

Figures VI-13 indicates that fuel cell trucks fueled with blue hydrogen will have greater emissions than new, efficient diesel buses. This rather surprising result is due to the fact that near-future diesel Class 8 combination trucks assumed in the calculation would be about 30% more efficient than the present average are compared to fuel cell trucks. Battery electric trucks, with 2025 estimated fuel efficiency and grid emissions would have about the same warming impact as a diesel truck and significantly lower than a fuel cell truck. However, it should be noted that that even though the battery truck warming impact would initially be about the same as a diesel truck, in an increasingly cleaner electricity grid could make the impact of the truck much smaller throughout its lifetime.

Despite these differences in emissions, both batteries fuel cell electric trucks have an important environmental justice advantage: they both significantly reduce tailpipe air pollution when displacing diesel trucks. Crucially, battery and fuel cell trucks do not emit particulates from fuel combustion, unburned hydrocarbons, and nitrogen oxides pollution at the point of use. Thus, they would reduce air pollution in communities all over the county, with either battery or fuel cell trucks.

Beyond air quality implications and carbon emissions, there are other factors that may differ between battery and fuel cell trucks. For example, range and weather are major, related factors that can affect the choice between battery electric and fuel cell Class 8 trucks. Fueling time can also be a factor.

Several these factors were analyzed by the National Renewable Energy Laboratory,[340] which has made a total-cost analysis of a variety of vehicles, including long-haul (750-mile and 500-mile rated ranges) and short-haul (300-mile range) Class 8 battery and fuel cell vehicles that are driven for one shift or multiple shifts. While present estimates indicate that the first cost of battery electric vehicles would be considerably higher than diesel trucks, this increased cost is overcome in essentially all cases by lower fuel and lower maintenance costs in all cases except the 750-mile rated range when driven for multiple shifts in a day. In the latter case, the lower payload of the battery truck (due to higher battery weight) and the long "dwell" time for charging when the truck must wait are large enough to more than negate the fuel and maintenance cost advantages of battery trucks.

The relative merits of long-distance, multiple-shift heavy duty fuel cell trucks relative to battery-electric trucks must be seen as tentative since there is little experience with them. In this comparison, the real issue in such cases is the loss of revenue due to charging or refueling time. This cost difference can be mitigated by accurately accounting for the social cost of carbon emissions. This point is illustrated by a lifecycle cost analysis of Class 8 trucks estimated that a typical truck might have three owners (a large fleet, a small-fleet, and an individual-owner operator) and be operated for a total of about 1.5 million miles over 15 years.[341]

Using these lifecycle figures, we can calculate the greenhouse gas emission differences per year between a battery electric truck charged from the electric grid (national average emissions) and a fuel cell truck with hydrogen made from natural gas with no CCS. The former emissions would start at about 140 metric tons CO_2-eq per year and go to zero by 2035 if the national goal of decarbonizing the grid is

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[340] NREL 2021b

[341] Research and Markets 2019

achieved. The latter would decline slightly due to the plan to reduce methane leaks by 30% by 2035. Overall, the cumulative difference over the life of the truck over 15 years (i.e. by 2038) would amount to about 2,000 metric tons of CO_2-eq. At $100 per metric ton for the social cost of carbon, the difference amounts to over $200,000 in the life of a single truck. The difference would be reduced with blue hydrogen fuel trucks, but it will take years before a significant quantity of blue hydrogen is produced because CCS facilities linked to hydrogen production do not yet exist at scale. It would also require a hydrogen fueling infrastructure for a very limited class of freight transport, given that the economics and climate aspects favor battery vehicles in practically all other cases except certain long-haul trucks that can legally be driven for up to 8 hours without mandating a 30-minute break for truckers to rest and fuel their vehicle.[342]

Given the considerations above, we assume that battery trucks would be used where feasible – that is for short and medium distance trucks that operate normally on one or two shifts (rather than three) per day, drayage trucks, and the like. Only trucks operating long distances, for three shifts a day and possibly long-distance single-shift trucks operating in very cold weather might need to be fuel cell trucks. The technology is evolving fast. The CEO second largest European truck manufacturer, MAN, expects that the role of fuel cell trucks will be limited to those with the largest loads such as large wind turbines which can weight 150 to 250 metric tons; this is far above the 40 ton load for normal Class 8 trucks.[343]

All combination trucks travelled about 179.8 billion miles in 2020, up from 175.3 billion miles in 2019.[344] This figure includes Class 7 and Class 8 trucks – the latter are about 92% of the total, however Class 7 and 8 trucks include all manner of vehicles from large school and transit buses to agricultural tractors, to construction equipment, to municipal waste collection vehicles, to tractor-trailers used to haul freight, the main concern of this section. Roughly half of vehicles in the heavy-duty vehicle category are freight related.[345] Overall, a little over 10% of heavy-duty vehicles operate with a range of more than 500 miles.[346] All others operate at lesser distances, in which case the need for fuel cell trucks would be low such in regions of very cold winters where range may be degraded in battery vehicles to an unacceptable extent. Lower operating cost would be the major reason for such a choice. For instance, the CEO of Europe's second largest truck manufacturer, has stated that "80% to 90%" of logistic trucks would be battery vehicles. Finally, in the long-distance category the main attraction of a fuel cell truck relative to a battery truck would be one that is operated in multiple shifts per day requiring quick refueling times; this would favor fuel cell trucks, at least given present technology.

Given the above an assumption that 10% of Class 8 vehicle miles would be fuel cell trucks – mainly those operating multiple shifts and large distances – provides a reasonable estimate, though admittedly rough. At present efficiencies of fuel cell trucks (about 7 miles per kilogram of hydrogen) hydrogen demand for 10% of the 2019 miles would amount to about 2.5 million metric tons per year.

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[342] DOT 2022

[343] Martin 2023b

[344] Unless noted, the rest of this paragraph is based on tables in ORNL 2022, which is a database for transportation-related tables. Table numbers are cited in the paragraph. The entire set of tables can be downloaded in spreadsheet format at https://tedb.ornl.gov/wp-content/uploads/2022/06/TEDB_40_Spreadsheets_06012022.zip

[345] Inferred from ORNL 2022 Table 5.8 by including vehicles in the following categories: "For hire" , "manufacturing", "wholesale" , and "leasing", with an addition of 5% to account for tractor trailers in other categories.

[346] ORNL 2022, Table 5.7

The Federal Highway Administration projects growth in combination truck miles at 1.6% per year;[347] however this is not broken down by range of operation, which is the necessary parameter for estimating hydrogen. Taking it at face value would give a 2050 hydrogen demand for fuel cell trucks of about 4 million metric tons. If supply chains are shortened, as resilience would seem to require, the requirement may be considerably lower; we will assume 3 million metric tons at the lower end for estimation purposes.

f. Other transportation modes

For non-land-based vehicles such as ocean-going ships and aircraft, compressed hydrogen has too low a volumetric density to be useful as a fuel. In case of airplanes, cryogenic hydrogen may be considered, while ocean-going ships might run on hydrogen-derived ammonia. Ammonia (NH_3) is made from hydrogen and nitrogen and can be converted to nitrogen and water in fuel cells to generate electricity.[348] Alternatively, ammonia can be combusted in turbines for motive power. As also highlighted in Chapter IV, at current turbine development levels, burning ammonia can create the greenhouse gas nitrous oxide (N_2O) and other nitrogen oxides (NO_x) that cause air pollution.[349] In addition to ammonia, methanol produced from green hydrogen could be used as a fuel for aircraft and ocean-going ships.

For transportation modes other than road transport, the general caveat about round-trip efficiency applies: as outlined earlier in the transportation section, battery vehicles are much more efficient based on the use of primary energy than fuel cell vehicles. This insight can be applied to many transportation modes. For example, trains powered by electricity via wires are very common, but they now need to be compared with newly-developed fuel cell trains. Likewise, ferries transporting people and vehicles have been developed in both battery and fuel cell versions. Furthermore, short-haul battery aircraft are being developed, including by the National Aeronautics and Space Administration (NASA).0 For each of these applications, it is reasonable to assume that when direct use of electricity is possible, electrification will be the preferred option from a carbon emissions standpoint. This means that fuel cells or other hydrogen technologies would only be favorable if other considerations tilt the scales in their favor. However, electrification of long-haul aircraft of the type that carry people and cargo across continents does not seem like a realistic prospect at present.

Two examples where hydrogen might play a role are long-haul passenger aircraft and large ocean-going cargo ships: these types of transport require storing energy at high weight-based energy densities. These applications would drive up hydrogen demand. For example, aircraft account for 11% of US petroleum consumption. An additional 2% is used in large ships, adding up to over 2 million barrels of oil a day for aviation and shipping. Aircraft have becoming steadily more efficient over the decades; container cargo has made shipping more efficient. As a result, the amount of fuel needed does not increase in proportion to increased usage.

Aviation fuel

Liquid hydrogen as well as hydrocarbon fuels, called sustainable aviation fuels from a variety of sources have been proposed for aircraft as a fuel for jet engines.[350] Smaller aircraft that use it to generate

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[347] DOT 2021. While the referenced forecast is for 20 years, we have used the growth rate for 27 years so as to arrive at a rough estimate for the year 2050.

[348] Jeerh *et al.* 2021

[349] Kobayashi *et al.* 2019 and Bertagni *et al.* 2023

[350] IATA 2019

electricity in fuel cells are being commercialized,[351] as are battery powered aircraft;[352] the latter are more experimental, given the lower energy density of batteries and the weight penalty that implies. Liquid hydrogen has almost three times the energy density per unit mass compared to jet fuel but only about one-fourth the volume density. As a result, while weight of the fuel required is lower making for higher efficiency the volume is considerably higher, requiring aircraft redesign.[353] Airbus has the most ambitious program for hydrogen as an aircraft fuel.[354]

While use of hydrogen as a fuel in aircraft would eliminate the CO_2 emissions associated with jet fuel, there will be more water vapor, which will have a warming impact, notably for aircraft that fly in or close to the lower stratosphere. Thus, hydrogen will not eliminate warming impact of large aircraft but reduce is significantly.[355] This impact will be in addition to the warming impact of any hydrogen leaks.

Hydrogen and biomass have also been proposed as feedstocks for synthetic aircraft fuel.[356] In this case, the carbon in the biomass is simply re-emitted to the atmosphere. Whether it would be a “net-zero” fuel depends on a number of factors, including land use, soil carbon loss (or possibly enhancement), possible increase in converting forested or other non-agricultural land to food cultivation, and the sources of biomass. Using hydrogen for aircraft fuel also raises the risk of exposure to harmful chemicals, because current fossil-based jet fuel contains harmful aromatics like benzene, toluene, ethylbenzene and xylene.[357] These chemicals are particularly relevant for Environmental Justice communities, as exemplified by historic toluene exposure stemming from plastics recycling.[358] Furthermore, some researchers have highlighted that toluene is used to produce fuels called “liquid organic hydrogen carriers”.[359] Although the both widespread use of such hydrogen carriers and the potential required addition of organics to future synthetic aircraft fuel are far from certain, possible exposure to these chemicals is an important environmental justice concern, particularly as it would likely exacerbate the harm to communities already overburdened with toxic pollution.

Ocean-going ships

Hydrogen in the form of ammonia (NH_3) has been proposed as a fuel for ocean-going ships such as container cargo ships; it would be burned to replace the petroleum derived fuels.

Nitrous oxide can form during combustion under adverse conditions (such as engine startup and low-power operation). Nitrous oxide is a powerful greenhouse gas with a global warming potential of 273 relative to CO_2,[360] and is formed with the amount varying according to the conditions of combustion. Bertagni *et al.* (2023) have evaluated the amount of nitrous oxide formation at which burning ammonia would the same impact as the global average greenhouse gas emissions resulting from fossil fuel use.

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[351] Cox 2023
[352] NASA 2022
[353] IATA 2019
[354] IEA 2022, page 55
[355] IATA 2019
[356] IEA 2022, page 55
[357] CDC 1995
[358] Booker *et al.* 2022 and Earthjustice 2023
[359] Akhtar *et al.* 2021
[360] The 20-year and 100-year global warming potential values for nitrous oxide are identical.

They concluded that just 0.4% of ammonia converting to nitrous oxide would equal the warming impact of the fossil fuel replaced.[361]

If fuel oil for ships in the United States were replaced by ammonia, CO_2-eq emissions amounting to 29.4 million metric tons in 2021 would be avoided.[362] This corresponds to 400 trillion Btu of fuel oil which would be replaced by about 19 million tons of ammonia (requiring about 4 million tons of hydrogen).

However, whether there would be a net reduction of warming impact is a more complex question. The warming impact of nitrous oxide from ammonia use would equal the fuel oil emissions if about 0.6% of the ammonia turned into nitrous oxide. That is even before accounting for the climate impact of hydrogen leaks during hydrogen and ammonia production. Consequently, if the goal is a significant reduction of warming impact, nitrous oxide would have to be controlled very stringently while simultaneously strictly limiting hydrogen leaks. For instance, there would be no room for nitrous oxide emissions whatsoever if hydrogen leaks were 5%. And, at 2% hydrogen leaks, no more than 1 out of 2000 molecules of ammonia could result in nitrous oxide emissions (all values rounded to one significant figure).[363]

Alternatives that could be considered include electric container cargo ships, which have been built for coastal transport, though a much smaller size than typical ocean-going container ships.[364] Larger container electric ships are also being designed: in July 2023, China launched a fully electric container cargo ship with a range of 600 miles meant for river routes. It has an 1,800-kW battery designed to be swapped at river ports.[365] Partial powering of cargo ships with solar and wind electricity is also possible. For instance, a partially wind-powered cargo ship that can reduce emissions by up to 30% was launched in August 2023.[366] Thus, given the expense, pollution, environmental justice impacts, and water impacts of hydrogen (and hence ammonia) production, full or partial electrification of cargo ships should be carefully examined as alternatives.

Time horizons are also important. As we have seen in Chapter VI, even when green hydrogen produces climate benefits, there are significant opportunity costs in the short- and medium-term (the next decade or so) of using renewable electricity to produce hydrogen instead of directly to meet the energy requirement. Compared to these time scales, developments in shipping are relatively rapid. Therefore, before the federal government subsidizes ammonia use in ships (or other energy use applications), a careful analysis of the alternatives and opportunity costs is indicated.

It is difficult, given the early stages of decarbonization of these transportation sectors, to estimate how much hydrogen may be needed in these sectors. The demand may escalate rapidly once the

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[361] A Btu for Btu replacement – that is, no change in efficiency – is a reasonable assumption in this case since both fuel oil and ammonia would be burned in engines.

[362] EPA 2023b, Table 3-99

[363] The hydrogen requirements for making the ammonia would be about 3. 8 million metric tons; 2% leans and a GWP of 33 yields a GHG emission estimate of about 2.5 million metric tons or 8.4% of the 2021 marine shipping emissions. A rate of 0.06% ammonia conversion to nitrous oxide would result in about 11,000 metric tons or N2O or about 3 million metric tons of CO2-equivalent. The total would be about 5.5 million metric tons CO2-eq or about 20% of 2021 emissions resulting from fuel oil use.

[364] Infineon 2019

[365] Sustainable Ships 2023

[366] Lewis 2023

technologies are commercialized. One can do a heuristic calculation to illustrate the potential scale of demand in these sectors with the following assumptions:

- Energy demand stays about the same due to increases in efficiency, shift to other modes of travel, and shorter transportation distances for goods;
- Half of the energy demand is met by hydrogen or fuels derived from hydrogen;
- In the mix of fuels using hydrogen as an input, about three-fourths of the energy would come from hydrogen and the rest from other sources, such as biofuels, or biomass.

With these assumptions, U.S. demand for hydrogen for aircraft and shipping would be the energy equivalent of about three-fourths of a million barrels of oil a day – or somewhat over 12 million metric tons of hydrogen in the 2040s. The renewable electricity required to make this amount of hydrogen would equal about 15% of the entire US electricity generation in the early 2020s.

f. Summary of potential hydrogen uses for decarbonization

As discussed in the sections above, in some cases it is inappropriate to use hydrogen for decarbonization. In such scenarios, hydrogen can be dismissed for a variety of reasons, including speed of decarbonization, cost, efficiency, and in some cases, low or no climate benefit. In other cases, long term uses of hydrogen could increase due the need to make full use of renewable electricity that would otherwise be curtailed. In such cases, hydrogen would become a long-duration, especially seasonal, energy storage method, among others that are also available.[367]

Figure VI-14 shows the low and high estimates detailed above for applications where the use of green hydrogen could make a significant contribution by about 2050 to decarbonizing the energy system by that year. It compares the low-end estimates made here with those made by the DOE in its draft hydrogen strategy;[368] the high-end estimates made above also compared with the “optimistic” hydrogen case in the DOE strategy.

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[367] IEER is producing a report on long-duration storage for Just Solutions Collective that will include the potential of hydrogen to be one of the large-scale storage methods, among others such as compressed air storage and seasonal thermal storage. See Makhijani *et al.* 2024.

[368] DOE 2022

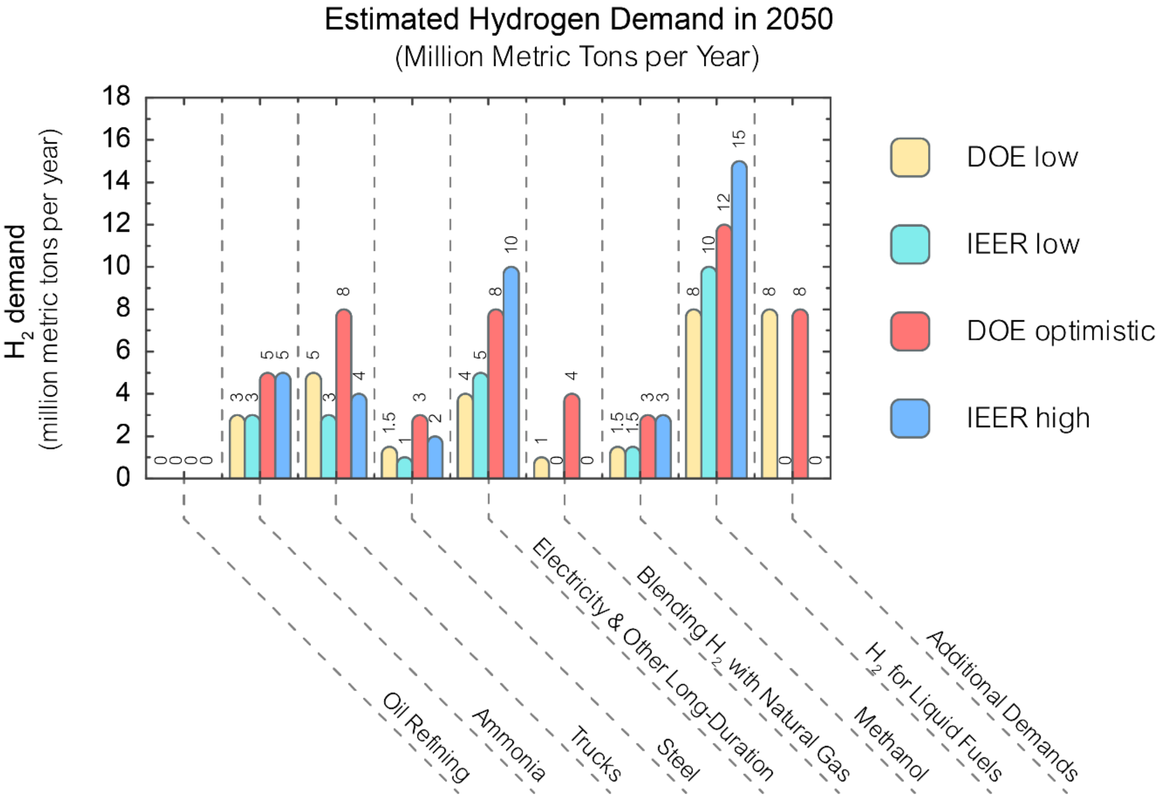

Figure VI-14: Overall hydrogen demand per end use.
Source: The analysis in the sections above in this chapter and DOE 2022, Figures 11 and 12. Note: Electricity requirements for hydrogen production, transportation to the point of use, storage: 50 MWh/metric ton.

The DOE draft strategy indicates a range of 30 to 50 million metric tons in the year 2050 (rounded), while the IEER analysis above indicates a range of 23 to 39 million metric tons by that date. The main differences are as follows:

- "Trucks": In the DOE's case, this includes medium and heavy-duty vehicles; the IEER analysis only includes long-distance Class 8 trucks.
- Heating buildings: The analysis in this report shows little to no climate benefit and significant cost and environmental justice disadvantages, leading to an assumption that there would be no significant use in this category were climate the priority.
- "Additional" demand: some of the DOE's additional demand is included in IEER's liquid fuels assessment. The rest such as exports is not included in the IEER analysis. It is possible that a few million metric tons per year above the IEER upper limit might be indicated for green hydrogen.

Given electrification of space and water heating, many uses of fossil fuels in industry, and most transportation, electricity requirements will increase substantially, even if efficiency is significantly increased for existing uses, like lighting and appliances. The primary energy sources for the vast majority of the total supply would be wind (onshore and offshore) and solar energy (at various scales). This in about a quarter of a century, the seasonal availability of electricity that does not have an immediate use or is not put into batteries would steadily increase. This would be used for long-duration storage. Were it all used for hydrogen, the total amount that could be produced in a fully decarbonized electricity system anchored by wind and solar energy, could be on the order of 30 million metric tons. However, there are many other long-duration storage approaches that might be suitable.[369] Considering that hydrogen is one of the most flexible energy carriers that is storable, it is not unreasonable to assume for purposes of initial estimation that two thirds of curtailed renewable electricity would instead be used to produce hydrogen. This would mean about 20 million metric tons of green hydrogen could be available by about 2050 from renewable energy that might otherwise be curtailed.

As a reminder of the caveats in the preface to this report, the estimates above do not constitute a recommendation for a particular amount of hydrogen production for specific uses. It is a narrow view of what might be reasonable, given cost reductions in green hydrogen production, from a climate point of view were hydrogen to be used to displace fossil fuels. Were ammonia use as fertilizer reduced for other economic, environmental, or climate reasons, the corresponding hydrogen production would not be needed. Similarly, if increases in steel recycling were feasible or encouraged by policy, the corresponding hydrogen production would not be needed. On the other hand, if the United States were to become a major exporter of green steel made from iron ore, hydrogen requirements would be increased.

There are also major technological uncertainties. The largest is in the development of technologies that would use electricity directly rather than for making hydrogen for a particular end use. Electrolysis of iron ore and the development of much batteries and infrastructure that could support truck charging in a few minutes are two major examples that would impact hydrogen use estimates. These caveats apply generally, rather than only to the estimates in this report.

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[369] Makhijani *et al.* 2024, forthcoming

VII. Environmental Justice Issues Overview[370]

This report is predominantly technical in focus, and therefore does not contain an extensive analysis of the environmental justice (EJ) issues associated with hydrogen production, storage, transportation, and use. Nonetheless, there are both local and global EJ issues in every step of the hydrogen value chain; for instance, EJ concerns are embedded in the catalyst materials needed for electrolyzing water or using hydrogen in fuel cells. On the flipside of this equation, there are also environmental benefits, even apart from those associated with reduction of greenhouse gas emissions when hydrogen displaces fossil fuels. For example, when green hydrogen displaces natural gas use, fracking-related water pollution, air pollution, and seismic risks are reduced. These examples illustrate that both environmental justice drawbacks and advantages span across local and global scales. Thus, EJ factors need to be considered at both scales, across all parts of the value chain.

a. Hydrogen production

i. Water requirements and water pollution

As discussed in Chapter IV, hydrogen production entails very large water demand. The exact amounts of consumption and withdrawal differ by production method, the purity of the water supply, and, in the case of electrolytic hydrogen production, the specific source of electricity. For example, using nuclear electricity to produce hydrogen vastly increase water use when the power plant uses fresh water for cooling. Because of this high water use, siting hydrogen production could be constrained by water supply; if inappropriately sited, hydrogen production could create significant equity issues, especially in the West and Southwest, where water is already a major concern. Significant issues of water rights and claims could arise. Use of water for hydrogen production could imply large opportunity costs in terms of water not available for other uses such as farming and domestic water supply. These issues are pertinent in the context of both conventional water resources and the recently suggested mining of brackish geologic aquifers or purifying water related to oil and gas production.

In addition, purification of water to the degree needed for electrolysis entails a rejected water stream that is approximately two to four times higher in salt concentration. This water is generally returned to the environment, but could create potential water pollution issues in sensitive ecosystems. Such concerns are particularly pertinent if salt water is used for purification, which creates a much more concentrated brine stream than fresh water purification does. If returned directly to marine ecosystems, animals and algae can die rapidly due to a phenomenon known as 'osmotic shock'.[371] Brine disposal problems also occur when creating salt caverns for hydrogen storage, because the required 'solution mining' process creates large volumes of brine (Chapter V).

Thus, hydrogen poses challenges related to water consumption, withdrawal and pollution. Simultaneously, great deal of water will be liberated as solar and wind energy displace thermo-electric power generation using fossil fuels. In addition, the elimination of fossil fuel generation will also result in the indirect reduction in water use for their production and the water pollution associated with it. Once

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[370] The issues listed in this chapter have been discussed or at least mentioned in the preceding chapters. References are not provided in this chapter unless a new issue is introduced.

[371] Fairley 2023

deciding how this liberated water should be used, significant issues of water rights and claims could arise. Use of water for hydrogen production could imply large opportunity costs in terms of water not available for other uses such as farming and domestic water supply.

ii. Blue hydrogen

Grey hydrogen, the main hydrogen production method used today, uses two raw material inputs: natural gas and water. These inputs are essentially identical for blue hydrogen, which uses the same process as grey hydrogen but adds carbon capture and sequestration, which increases both natural gas and water use. Consequently, producing blue hydrogen raises a host of environmental justice issues:

- Continued production and transportation of natural gas including that produced by fracking;
- Pollution issues associated with CCS, such as the release of ammonia due to the degradation of amine-based CO_2 sorbents;[372]
- The continued presence of polluting facilities in EJ communities, with new risks added to existing ones;
- Safety issues associated with CO_2 transport in pipelines through communities;
- Safety and environmental issues such as induced seismicity,[373] associated with injection of CO_2 in different geologic formations at the time of sequestration and over the long-term;
- Water-related issues in some cases;
- Pollution issues associated with the production of amines used in the most common method of carbon capture;
- Entrenchment of the natural gas industry and adverse economic and political consequences that may arise from that.[374]

iii. Electrolysis

Apart from water use, mentioned above, electrolysis involves the use of scarce materials like iridium and platinum as catalysts. The places where these materials are mined and refined would experience adverse impacts. Many are in the Global South and on Indigenous lands in the Global North. As with water, there is also the issue of net impact, since fossil fuel production and use also involves material production impacts that would be avoided when green hydrogen displaces them. Therefore, the following issues could be examined:

- The site-specific issues involving the main materials that must be mined and processed – with a focus on the Global South and Indigenous lands, including to illustrate differential impacts on communities near mining sites;
- Impacts of recovering and recycling hydrogen-related materials – as well as avoided mining and processing impacts;
- Global net impacts, including avoided fossil fuel impacts.

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[372] EEA 2011

[373] Cheng *et al.* 2023

[374] Blue hydrogen is one aspect of many proposals that would entrench the industry. Mixing hydrogen with natural gas is another. So are continuing large investments in natural gas distribution infrastructure. For an example and an analysis of the latter, see Makhijani 2023.

➢ Electrolysis safety

Electrolysis splits water into hydrogen and oxygen – the very mixture that can result in fires and explosions. Thus, keeping the streams of evolved hydrogen and oxygen separate is a primary design objective. As discussed in the section on power generation in Chapter VI, hydrogen production for the purpose of long-term energy storage could play and important role in the energy transition especially if the electricity used would otherwise be curtailed. This means intermittent operation of the electrolyzer. Certain designs are more amenable to such stop-start operation while there are safety risks associated with older alkaline electrolyzers (Chapter IV). However, there are still issues such as degradation of catalysts and hence demand for catalyst materials to be resolved for intermittent hydrogen production. In addition, as mentioned in Chapter V, highly flammable gas mixtures can form if air condenses on cryogenic hydrogen containers. The latter concern holds for all types of hydrogen, including grey and blue hydrogen.

➢ Comparing green and pink hydrogen

Besides the much larger water consumption associated with pink hydrogen – which is hydrogen produced by electrolysis of water using nuclear electricity – there are a host of issues associated with the use of nuclear energy that arise mainly from the fact that it involves the production and use of fuel whereas solar and wind energy do not. The specific impacts include:

- Uranium mining uranium mine wastes, health risks, water pollution, etc.
- Uranium milling and mill tailings associated issues, including air and water pollution;
- Uranium processing and enrichment, including depleted uranium wastes;
- Reactor community-related pollution and risks;
- Creation of plutonium in the course of reactor operation – each U.S. 1000 MW reactor (the typical present size) creates about 30 Nagasaki-size atom bombs worth of plutonium every year;
- Highly radioactive spent fuel – about 20 metric tons per reactor per year; the spent fuel contains the plutonium (~1%).

The longevity of these wastes is remarkable. For example, mill tailings contain thorium-230, with a half-life of about 75,000 years. Plutonium-239 has a half-life of over 24,000 years.

Both nuclear and renewable energy have impacts associated with the production of materials used to build the plants. Those materials and their associated impacts are substantial and different, but solar and wind do not need fuels, thus avoiding continuing impacts.

iv. Other hydrogen production methods

Landfill gas and biomass have been proposed as raw materials for hydrogen production. Given the location of landfills, this has evident environmental justice implications.

Biomass has implications for land use, climate, soil carbon, as well as the environmental justice issues associated with siting.

v. Global justice issues of hydrogen production

As is highlighted in this chapter and in Chapter IV, producing hydrogen can have effects across the globe. These effects can be associated with mining the metals that catalyze hydrogen production, but can also relate to hydrogen production itself. For example, it has been suggested that land-, and water-rich countries, including parts of sub-Saharan Africa, can produce hydrogen and export it to other countries.[375] Such export-based hydrogen production would exacerbate transport-related hydrogen leakage and pose additional pollution issues if hydrogen is transported in the form of ammonia (Chapter V). In addition, a 2022 report examined the production of hydrogen in Morocco, Niger and Senegal for export to Germany, and concluded that this process would impede decarbonization in the producing countries and risks renewing neo-colonial relations between producer and importing countries.[376]

b. Transportation and storage of hydrogen

Hydrogen transportation and storage mainly involve safety issues; they are discussed to an extent in Chapter V. There are additional safety issues that deserve consideration, particularly related to large-scale hydrogen storage in underground reservoirs:

- Siting issues including hazards to nearby communities.
- Leakage issues;
- Issues arising from hydrogen mixing with residual natural gas, in case underground reservoirs used for natural gas storage currently are converted to hydrogen storage;
- Induced seismicity potential, which is a particular concern for porous reservoirs in clay-bearing soils.[377]

c. Uses of hydrogen

Hydrogen emits only water (as a liquid or as a vapor) vapor when used to produce electricity in a fuel cell; this is basically the reverse of using electricity to split water into hydrogen and oxygen. If used in stationary applications, like power production, the water could be recovered and reused.

i. Burning hydrogen

Hydrogen creates air pollution in the form of nitrogen oxides when burned. Air pollution, and associated environmental justice impacts, can be explored in the various contexts in which hydrogen burning has been proposed:

- Use in turbines for generating electricity in place of natural gas;
- Use in combined heat and power plants in place of natural gas or fuel oil;
- Blending hydrogen and natural gas for power plants and combined heat and power, in which case the impacts of natural gas burning would be combined with those of hydrogen combustion;
- Use in buildings, transported in existing natural gas distribution infrastructure and mixed with natural gas has also been proposed. Indoor air pollution would be perpetuated, with disparate impact on households who could not afford the first cost of electrifying heating and cooking or on renters, especially low-income renters and among them BIPOC renters.

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[375] Tonelli *et al.* 2023
[376] Rosa-Luxemburg-Stiftung 2022
[377] Heinemann *et al.* 2021

ii. Fuel cell safety issues

There are many designs of fuel cells; they are discussed in Chapter VI. There are various safety and environmental issues associated with them. Fuel cells for power production are sometimes coupled with natural gas reforming to produce the hydrogen on site. Furthermore, fuel cells like solid oxide fuel cells can handle both hydrogen and methane as fuel (Chapter VI). These fuel cells have associated CO_2 emissions and can potentially propagate all of the environmental injustices that are associated with methane production for fuels.

iii. Synthetic fuel production

Liquid fuels such as ammonia and hydrocarbon fuels can be produced using hydrogen as one of the inputs. Other inputs, depending on the fuel type, could be captured CO_2, biomass, landfill gas, and biofuels made from crops. Such fuels are proposed for use in aircraft and ships, for instance, since neither electricity storage in batteries nor gaseous compressed hydrogen is suitable. However, it is possible that liquid hydrogen – that is hydrogen cooled to an extremely temperature to liquefy it, could be used, even in aircraft.

The manufacture of synthetic hydrocarbon fuels would constitute a major new chemical industry, with attendant economic, ecological, and environmental justice implications. It could also constitute a major use of hydrogen, the extent of which would depend on which specific fuels and technologies come to widely used. It is also unclear whether future synthetic fuels would require additives like toluene and benzene, which are jet fuel additives. If so, hydrogen use to make synthetic fuels would add to the toxic burden in communities that are already seriously already overburdened.[378] Furthermore, if combusted, synthetic fuels would propagate the similar air pollution and public health effects that are associated with burning fossil fuels. As discussed in Chapter V, these effects can be exacerbated if ammonia is burned in gas turbines, which creates significant NO_x emissions if used in currently available turbines.

iv. Perpetuation of the natural gas industry

A significant role for blue hydrogen brings with it the risk of a long-term role of natural gas in the energy system. This would perpetuate the many environmental justice and ecological impacts of natural gas production and use; moreover, a full elimination of natural gas leaks would be highly unlikely, as is 100% CO_2 sequestration. This raises many economic, ecological, environmental justice, and climate issues for possible detailed study.

Similarly, mixing hydrogen with natural gas for use in building heating and power production, widely proposed, would have minimal climate benefits even with green hydrogen. It would serve the purpose of entrenching the natural gas industry in the energy system. A detailed exploration of this use in the residential sector impact could be done from the economic, environmental justice, and climate aspects.

Mixing hydrogen into the natural gas network also creates safety concerns, because hydrogen is combustible and explosive when mixed with air over a wide concentration range of 4% to 76% by volume. Since hydrogen is a widely used commodity, the basic safety issues of handling pure hydrogen are understood, but there is little experience with more novel applications such as mixing hydrogen with

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[378] EPA 2023c

natural gas in existing natural gas infrastructure and the burning of hydrogen in turbines; mixing rates by volume of 20% and even 50% have been proposed. Safety issues that should be examined include:

- Potential degradation of natural gas distribution infrastructure due to hydrogen mixing at various levels;
- Risks arising from potential increased leaks in an already leaky natural gas infrastructure in many places;
- Change in safety risks in indoor spaces relative to natural gas if blended hydrogen is piped into homes.

v. Steel

Using hydrogen for steel production instead of coke significantly reduces greenhouse gas emissions even with grey hydrogen; it reduces them more with blue hydrogen and eliminates them when using green hydrogen in a decarbonized grid. Since green hydrogen is scarce and expensive and there are many competing uses for renewable energy and even green hydrogen, the question arises whether *already available* grey hydrogen could be used for an early transition in the steel industry to get GHG emission reductions without CCS. Here, the end goal would still be to transition to green hydrogen from grey as that becomes available in larger quantities, possibly in a decade or more. Such use of grey hydrogen would displace the continued use of coke, which emits more greenhouse gases and a variety of other toxic pollutants, as discussed in Chapter VI Section b.iv. This is a complex economic, environmental justice, and climate issue. A more detailed examination is needed to clarify its implications for natural gas and green hydrogen from an environmental justice standpoint.

vi. Opportunity costs of using hydrogen

There are a number of areas where the use of green hydrogen would reduce CO_2 emissions but would represent a waste of renewable energy resources. Other things being equal, even approximately, the use of renewable electricity directly or coupled with storage is far more beneficial for decarbonization and more economical. Some examples of the significant lost opportunities for climate and economic justice are in the report, such as in the section on transit buses in Chapter VI.

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