
ENERGY INNOVATION POLICY & TECHNOLOGY LLC®

RETA Regulatory Energy Transition Accelerator

# REGULATING HYDROGEN

## A Primer for Energy Regulators

**Dan Esposito and Mike O'Boyle**

**June 2025**

**Photo Credit: Shutterstock 2306257173**

# TABLE OF CONTENTS

## ABOUT ENERGY INNOVATION

Energy Innovation Policy & Technology LLC is a non-partisan energy and climate policy think tank. We provide customized research and policy analysis to decision-makers to support policy design that reduces emissions at the speed and scale required for a safe climate future.

## ABOUT THE REGULATORY ENERGY TRANSITION ACCELERATOR

The Regulatory Energy Transition Accelerator (RETA) is an initiative to enhance the capacity of regulators to increase the speed of the clean energy transitions. It works directly with energy regulators in order to facilitate knowledge sharing, peer to peer learning, and thought leadership on regulatory issues. It acts as well as a central resource for regulators to seek knowledge products and regulatory tools that can help mitigate challenges regulators face when trying to regulate for the sustainable, affordable, and secure energy systems of the future. The Accelerator was launched in 2021 at COP26 by Ofgem, the International Energy Agency (IEA), the International Renewable Energy Agency (IRENA), the World Bank, RMI, Energy Innovation, and Regulatory Assistance Project (RAP) along with regulators from around the world as part of the Green Grids Initiative.

## ACKNOWLEDGEMENTS

The authors would like to acknowledge peer reviewers for their input, guidance, and contributions to this paper. The contents and conclusions, including any errors and omissions, are the sole responsibility of the authors, and peer reviewer input does not imply their support or endorsement of the work. Peer reviewers from regulatory agencies include Ivan Lapczak at the British Columbia Utilities Commission (Canada); John Lau and Rachel Anderson at the Ontario Energy Board (Canada); Álvaro Ruiz, Jerson Reyes, and Yamal Soto at the Comisión Nacional de Energía (Chile); Annegret Groebel at Bundesnetzagentur (Germany); Noura Hajri at the National Electricity Regulatory Authority (Morocco); Justin LéVeque and Katie Mulvaney at the Colorado Public Utilities Commission (U.S.); and James M. (Jamie) Van Nostrand at the Massachusetts Department of Public Utilities (U.S.). Peer reviewers from research firms, NGOs, and academia include Matthias Deutsch at Agora Industry; Anne-Sophie Corbeau at the Center on Global Energy Policy at Columbia University; Sara Baldwin at Energy Innovation; Luca Lo Schiavo and Onur Uyanusta at the Energy Regulators Regional Association; Herib Blanco at the International Energy Agency; Gayathri Nair and James Walker at the International Renewable Energy Agency; Carrie Schoeneberger and Pete Budden at the Natural Resources Defense Council; and Alejandro Hernandez, Dominic Scott, and Ronny Sandoval at the Regulatory Assistance Project.

The authors would like to give special thanks to Eleanor Stein at the State University of New York as well as Esra Bozkir Broekman, Floris van Dedem, and Gyuri Cho at the International Energy Agency for being close collaborators since the genesis of this project, although errors and omissions remain those of the authors, and these individuals' collaboration does not imply their support or endorsement of the work. Finally, the authors gratefully acknowledge Energy Innovation colleagues Greg Alvarez, Shannon Stirone, and Silvio Marcacci for their communications contributions to this paper.

# EXECUTIVE SUMMARY

At least 74 countries have released national strategies or roadmaps on hydrogen.[1] These plans recognize that low-emissions hydrogen—a gaseous molecule produced in a manner that emits relatively little climate pollution and used as a chemical feedstock and energy carrier—is important to solving climate change. It also offers opportunities for governments to improve industrial competitiveness, innovate and invest in their energy sectors, and enhance national security. However, these plans are running up against economic and technological realities, often first in energy regulation.

Energy regulators who oversee electricity and gas networks, wholesale markets, and retail markets take these plans or policy targets and have to dig several layers deeper into implementation. A common realization, and perhaps the central challenge, is that the future of hydrogen is highly uncertain. The International Energy Agency's (IEA) recent change to its low-emissions hydrogen demand forecast for 2050 exemplifies this uncertainty: It fell by nearly a quarter from its 2021 to its 2024 Net Zero Emissions by 2050 (NZE) Scenarios to 401 million metric tons (MMT), and various organizations' 2050 hydrogen demand forecasts differ by more than 200 MMT.[2]

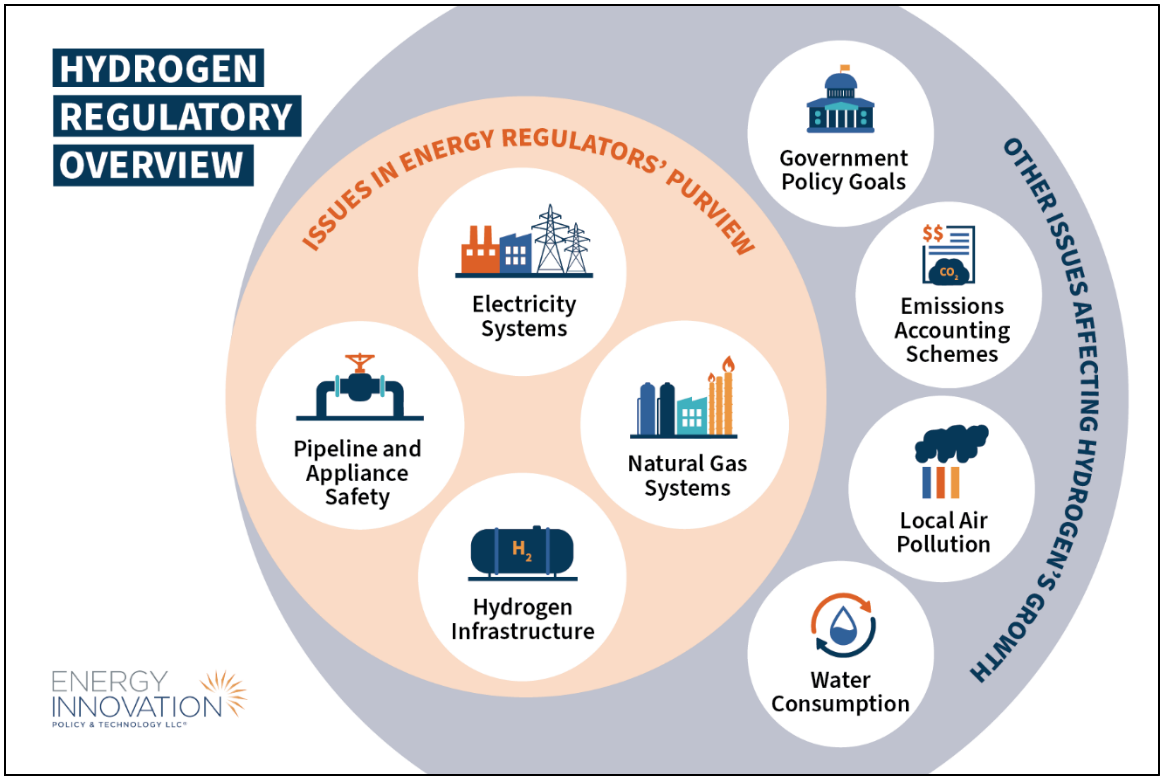
While low-emissions hydrogen can develop a new clean industrial base that serves and decarbonizes myriad end uses, it is difficult to actually reduce emissions from hydrogen production, and it competes in each sector with other clean technologies on their own learning paths. A complex range of possibilities emerges that depends heavily on policy, technology, and economics. On one hand, reaching net-zero emissions requires decarbonizing and likely vastly increasing hydrogen production. On the other, mismanaged hydrogen production can fail to adequately reduce—and even worsen—climate pollution, and hydrogen is not well suited as an energy carrier in many of the areas in which it is being considered. Ultimately, hydrogen policy goals are not good indicators of real-world demand, as buyers seek a cost-effective, low-emissions product.

A quandary lies at the center of regulating energy under ambitious hydrogen policy: Regulators risk approving investments that will be stranded and saddling customers with the bill if they are too bullish, but they can also stifle needed growth in hydrogen development if they are too reactive. Regulators can differentiate hype from reality by starting now to think through and plan for the many ways low-emissions hydrogen's production and use may affect regulated energy systems. The uncertainty of future demand complicates regulators' jobs as they oversee existing electricity and gas networks and assess regulated companies' role in delivering hydrogen to chemical producers, industrial factories, and other end-users seeking to reduce their climate impacts. To enable this future, regulators need to develop and reinforce technical capabilities on hydrogen and learn from one another about emerging best practices.

To assist regulators grappling with hydrogen's role in future energy systems, Energy Innovation and the Regulatory Energy Transition Accelerator (RETA) co-convened two discussions with regulators from around the globe. The sessions focused on regulators' experiences and decisions regarding low-emissions hydrogen, as well as regulatory peer-to-peer discussions to identify common issues and research needs. The workshops made clear that there is a need to develop proactive approaches that balance meeting hydrogen policy goals with regulators' remit to ensure affordable, reliable, and safe energy services for all customers.

This paper provides energy regulators with a primer on hydrogen regulatory considerations as well as a strategic framework to begin developing the right approach for their jurisdictional context. We provide an overview of issues and give examples of regulatory responses within energy regulators' purview, including recommendations to address specific questions and priorities related to hydrogen. We also shed light on public policy considerations that will impact regulatory decisions but are outside of most energy regulators' scope. Finally, we offer a brief topical research bibliography in Appendix A and additional background information on hydrogen in Appendix B.

***Figure 1. Overview of hydrogen regulatory issues***




*While most energy regulators only have jurisdiction over the "issues in energy regulators' purview," they can make smarter decisions on these issues by widening their aperture of awareness to consider—and coordinate with other agencies and authorities on—these "other issues affecting hydrogen's growth" that may fall outside of their direct decision-making power.*

Four issue areas will directly affect energy regulators: electricity system regulation, gas system regulation, hydrogen pipeline and distribution network regulation, and safety regulation. Different regulators' interaction with these issues will vary depending on their mandates and contexts. For instance, some regulators have more legislated authority than others to regulate hydrogen-related activities.

**Electricity systems** under regulators' jurisdiction are most likely to encounter hydrogen as new electricity demand via electrolytic hydrogen production, as well as a potential source of demand flexibility and seasonal energy storage that collectively complements wind and solar generation. Even with strong policy support, hydrogen demand is highly uncertain, complicating the task of planning infrastructure to power hydrogen electrolyzers. Regulators will also want to consider electricity pricing schemes that encourage electrolyzers to operate flexibly while ensuring large consumers pay their fair share—benefiting the overall system. Finally, hydrogen will have to compete against other technologies to provide seasonal energy storage in a highly decarbonized power system with high shares of variable wind and solar power.

We highlight the following priorities for electricity regulators in this context:

1. Engage with electricity distribution companies, industry, and consumers to better understand the potential impacts of hydrogen electrolysis on the electricity system, assess the reasonableness of electricity demand projections, and discern how to protect consumers while meeting this demand.
2. Develop electricity prices and interconnection schemes that encourage flexible electrolyzer operations that align with carbon goals, promote low-cost hydrogen production, minimize new infrastructure, and protect existing customers.
3. Study the technology set, including hydrogen, that could provide dispatchable capacity and seasonal storage needs in a low-emissions electricity system.

**Natural gas systems** under regulatory control are also likely to interact with hydrogen. Hydrogen production can affect natural gas demand—however, the precise volumes of hydrogen that would be derived from natural gas with carbon capture, utilization, and storage (CCUS) in the future are highly uncertain as this pathway competes with electrolytic hydrogen to serve even more uncertain demand. Separately, some jurisdictions and gas companies envision hydrogen as an energy carrier to provide heat to buildings and industry as natural gas does today. Some gas companies are already piloting blending hydrogen into existing natural gas networks, including distribution systems to households. However, a wealth of technical assessments suggests hydrogen's opportunity in decarbonizing low-temperature heat will be limited to niche circumstances, especially via blending hydrogen into existing natural gas distribution networks for use in consumer appliances.[3] Finally, natural gas distribution companies are also considering repurposing natural gas pipelines to transport hydrogen.

We highlight the following priorities for natural gas regulators in this context:

1. Engage with natural gas distribution companies, industry, and consumers to better estimate how low-emissions hydrogen demand will impact natural gas

demand and prices—via the use of natural gas for hydrogen production, the use of repurposed natural gas infrastructure for hydrogen delivery, and the displacement of natural gas from hydrogen's use downstream.

2. Examine the relative safety, cost, environmental, and feasibility implications of using hydrogen to decarbonize different heating needs (e.g., buildings, industrial processes), placing a heavy burden of proof on industry proposals and learning from other jurisdictions' assessments. Work with stakeholders to compare hydrogen blending or reuse of natural gas infrastructure with the full range of alternatives including clean electrification, biofuels, thermal energy networks,[i] and other solutions.
3. Assess the viability and cost of repurposing natural gas pipelines for hydrogen transportation. Where hydrogen production and demand are likely to increase and require transportation, assess whether existing pipelines are particularly well-suited for reuse and how cost recovery for reused assets would be treated, then begin to incorporate these decisions into gas system planning.

**Hydrogen pipeline and distribution networks** may develop in such a way that requires direct regulation, similar to other energy networks. Though today in most jurisdictions the hydrogen industry is far from exhibiting characteristics such as customer harm or natural monopoly, regulators can benefit from thinking through the market structure that will best serve customers. For example, what are the appropriate limits for incumbent regulated electricity and natural gas companies to own and operate hydrogen infrastructure, especially where self-dealing may be involved? While hydrogen production and pipelines are likely to begin at a business-to-business level—as is the case with conventional hydrogen in the refining, chemicals, and metals industries—regulators should be vigilant in monitoring the market and develop a proactive approach to regulating hydrogen infrastructure that protects customers:[4]

1. Clarify regulatory principles for hydrogen regulation from the outset, and define the limits and terms for incumbent monopoly businesses to participate.
2. Foresee temporary regulatory exemptions for existing and new hydrogen infrastructure developed as business-to-business networks.
3. Value the benefits and costs of repurposing natural gas assets for transporting hydrogen, and verify those cost estimates in any demonstration projects.
4. Avoid cross-subsidization between the natural gas and hydrogen networks when natural gas assets are repurposed for hydrogen transport.

**Safety risks** arise from hydrogen's unique chemical properties, which make it more challenging to manage compared with methane. Hydrogen leaks readily as it is the smallest molecule and can "embrittle" metal pipelines by permeating and creating

---

[i] Thermal energy networks "heat and cool buildings at the campus, block, or neighborhood scale with non-combusting, non-emitting thermal sources such as geothermal energy or waste heat using a network of interconnected underground pipes. See generally: [https://www.ilr.cornell.edu/sites/default/files-d8/2024-12/understanding-thermal-energy-networks.pdf](https://www.ilr.cornell.edu/sites/default/files-d8/2024-12/understanding-thermal-energy-networks.pdf)

fissures in their walls. It is undetectable by human senses, combusts more readily in a wider range of mixtures with air, has a faster flame speed that can travel back through pipes to damage equipment, and burns hotter with a barely-perceptible flame. Chemicals industries have safely managed hydrogen with purpose-built infrastructure for decades, so presumably these challenges can be overcome. However, energy companies may seek to use or repurpose infrastructure that was not purpose-built to handle hydrogen, such as natural gas pipelines and consumer appliances. Regulators must be attuned to safety risks and gas quality considerations to protect people from explosions and prevent equipment damage, focusing in the following areas:

1. Establish and update natural gas and hydrogen infrastructure safety standards—with monitoring and enforcement mechanisms—to account for hydrogen's unique characteristics, including for pipelines and storage systems.
2. Learn from industry, standard-setting organizations, and other jurisdictions about hydrogen purity and the limitations of hydrogen blending in natural gas pipelines, consumer appliances, and industrial equipment—including risks related to safety, leakage, gas quality, and compatibility—in order to support broader regulatory decision-making on hydrogen infrastructure investment.
3. Ensure hydrogen providers meet high standards of financial reliability, accountability, and performance.

In addition to these direct impacts on regulated energy systems, regulators will have difficulty developing a proactive strategy for regulating hydrogen unless they keep in mind other policy concerns that affect hydrogen's viability and coordinate with relevant agencies and authorities on appropriate actions.

We highlight the following:

- **Government policy goals:** Governments' hydrogen goals are meant to drive legislation, regulation, and investment that support policy goals such as decarbonization, international competitiveness, and national security. However, the degree the hydrogen industry will develop to meet these ambitious goals is highly uncertain and dependent on regulatory implementation. Regulators' decisions can help achieve progress toward these government goals by enabling investment or giving access to low-cost clean electricity, but their core mandate lies in ensuring affordable, reliable, and safe provision of service from regulated industries for all consumers. Regulators should not view hydrogen policy goals as a certain outcome—particularly given rapidly changing policy, technology, and economic outlooks—but should approach them in a manner that supports their development while minimizing risk. Ideally, regulators can share their perspective on these national or sub-national policy decisions at an early stage to inform wise target-setting while developing a realistic, proactive approach that anticipates government policies and protects the public interest.
- **Emissions accounting schemes:** Policymakers often define low-emissions hydrogen in terms of emissions intensity, which necessitates development of

emissions accounting rules. The emissions accounting framework—and the subsidies that may be tied to it—will affect the quantity and price of hydrogen, the credibility of the "low-emissions" qualifier and actual amount of climate pollution, the technologies deployed to supply the hydrogen, the demands that hydrogen production places on electricity and gas supply, the operational profile of electrolyzers, and the markets to which the hydrogen has access (e.g., "low-emissions" hydrogen in one jurisdiction may not count as "low-emissions" in another). These frameworks are also likely to evolve over time, because the progression from current "low-emissions" definitions toward zero-emissions hydrogen will be necessary to achieve a net-zero economy. Understanding these nuances can help regulators design smarter accounting schemes—if applicable—or at least better assess load forecasts.

- **Local air pollution:** Hydrogen combustion—as well as hydrogen produced from fossil fuels—generally results in emissions of nitrogen oxide (NOx), which is an air pollutant that harms human respiratory systems. Depending on the jurisdiction's environmental regulations, these NOx challenges can conflict with existing pollution standards and complicate or defeat certain methods of producing or combusting hydrogen.
- **Water usage:** Hydrogen production draws on water resources in several ways: directly (e.g., water for electrolysis or steam), indirectly (e.g., cooling processes), and upstream (e.g., water treatment). The total water requirement is quite small as meeting the IEA's NZE Scenario hydrogen production forecast would entail less than a quarter of one percent of global freshwater resources.[5] However, the location and context of hydrogen production and use are critical for protecting freshwater availability in water-stressed regions. A lack of available freshwater—or the costs of desalination and brine management—may limit electrolytic hydrogen production, with implications for the hydrogen industry's development and its impact on regulated electric and natural gas systems.

These many areas of regulation and policy create a complex picture—hydrogen is a policy priority for many governments, and its production and use affect the energy system, trade, climate progress, air quality, and water availability.

Energy regulators may have relatively limited jurisdictional lenses, but making the best decisions on matters within their purview would benefit from widening their aperture of awareness. They should seek to understand the technological, economic, and policy fundamentals that will drive the hydrogen industry's development over the coming decades. They should coordinate with other regulators and authorities (e.g., with purview over environmental issues or in other jurisdictions). And where opportunities arise, regulators can share their perspectives and analysis to support government bodies in developing and updating hydrogen strategies such that they better account for energy system realities. Such proactive insight and collaboration will help cut through exceptionally high uncertainty to illuminate least-regrets paths forward that support regulators' core mandate.

# INTRODUCTION

Hydrogen is a gaseous molecule that is emerging as part of the energy transition for its value as a chemical feedstock and energy carrier. While a large hydrogen industry exists today, its production is highly polluting, and it is mostly confined to refineries and petrochemical parks. Recent policymaker and energy company interest around the world is driven by the ability to produce "low-emissions" hydrogen and use it to reduce climate pollution from these and other hard-to-abate fossil fuel-using industries and sectors. Additional interest comes from hydrogen's economic and energy security potential. Governments may want to develop low-emissions hydrogen to export it (or the technologies that produce or use hydrogen) to jurisdictions with emissions reduction goals, to explore the viability of repurposing natural gas infrastructure and equipment that may otherwise be stranded in a low-carbon future, or to diversify their domestic energy supply.

Hydrogen can be made using electricity or natural gas, and it can be used to generate electricity or provide similar services as natural gas. These interactions suggest energy regulators will encounter hydrogen as part of their current mandates to ensure affordable, reliable, and safe electric and natural gas service. Questions also arise as to the extent to which energy regulators should oversee hydrogen network and market development and how to ensure safe operation.

This paper seeks to support regulators by:

- Providing regulators with information on the basics of hydrogen technologies and hydrogen's role in reducing industrial and energy system carbon emissions
- Helping regulators prepare for energy companies' hydrogen proposals, including via an overview of hydrogen regulatory issues, guiding questions, and priorities
- Sharing existing resources that address or more deeply consider some of these issues and questions, highlighting answers when available and broadly applicable

This section reviews the recent global acceleration of hydrogen policymaking, discusses hydrogen's role in reducing climate pollution, provides an overview of hydrogen workshops for energy regulators convened by Energy Innovation and RETA, and previews the rest of this paper.

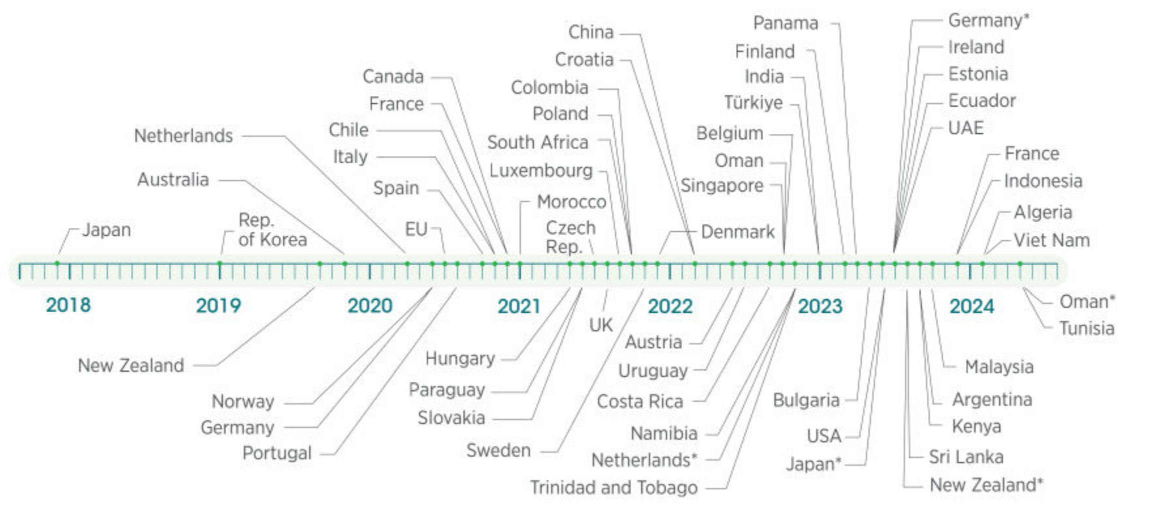
## Hydrogen activity around the world

The IEA forecasts a global need for 260 MMT of low-emissions hydrogen by 2050 in its Announced Pledges Scenario (APS) and 401 MMT in its NZE Scenario.[6] In both cases, approximately 80 percent of this production is forecast to come from electricity, with nearly all of the remainder from fossil fuels (principally natural gas) with CCUS. Reaching the APS and NZE Scenario levels would require 10 to 15 percent of 2050 global electricity supply (7,000 to 12,000 terawatt-hours) and 9 to 28 percent of 2050 global natural gas demand (219 to 246 billion cubic meters), respectively.[ii,7]

In hydrogen, as with so many other clean technology arenas, the world is off track for reaching its net zero goals by 2050. Even in a decarbonized world, hydrogen is not guaranteed to play this large of a role. Other emerging technologies are competing to serve the same set of needs. This uncertainty is clear from forecasting bodies' varied and changing estimates—for example, IEA's low-emissions hydrogen demand forecast for 2050 fell by nearly a quarter from its 2021 to its 2024 NZE Scenarios, and various organizations' 2050 hydrogen demand forecasts differ by more than 200 MMT.[8]

Many jurisdictions have at least started planning for the growth of low-emissions hydrogen, often as part of both industrial and climate strategies. At least 74 countries were involved in drafting national hydrogen strategic planning documents, seeking to assess the potential—and realize anticipated economic and emissions reduction benefits—of low-emissions hydrogen.[9]

***Figure 2. Timeline of hydrogen strategies and roadmaps (as of May 2024)***




**Note:** Updates are indicated with an asterisk; EU = European Union; Rep. of Korea = Republic of Korea; Czech Rep. = Czech Republic; UAE = United Arab Emirates; USA = United States of America.

*Dates represent when jurisdictions published or (when denoted by an asterisk) updated their hydrogen strategies or roadmaps. Source: IRENA.[10]*

National hydrogen strategies can lead to policies that directly support or require the deployment of hydrogen technologies and enabling infrastructure. Or they can simply outline the opportunity and leave it to economic regulators to sort through the details.

---

[ii] The values for natural gas demand used for low-emissions hydrogen production include only "merchant" hydrogen (produced for sale to other parties), excluding hydrogen production for use on site. As the latter can be substantial, the actual natural gas demand implicated by low-emissions hydrogen production could be much larger than described here.

Much of low-emissions hydrogen's growth depends on the cost of clean electricity and natural gas—a matter squarely in the purview of energy regulators. On the other hand, such regulators may have no control over the economic incentives policymakers pass to promote hydrogen production, technology improvement, and infrastructure access—although they may be able to coordinate with governments in sharing analysis that can shape the establishment and revisiting of these goals and policies.

## Hydrogen's role in reducing carbon emissions

Global hydrogen production in 2023 totaled 97 MMT—nearly all from unabated fossil fuels via the conventional process of steam methane reformation—and emitted 920 MMT of carbon dioxide ($CO_2$), or nearly 2 percent of global greenhouse gas (GHG) emissions.[11] Almost all of this "gray" hydrogen was used to refine oil, make chemicals (mostly ammonia and methanol), or purify iron ore for steelmaking. Hydrogen production and use has generally taken place either at large integrated facilities for self-consumption or within dense industrial clusters connected via purpose-built hydrogen pipelines.

Hydrogen is of growing interest for the energy transition because—at least in theory—it *can* be produced without emitting greenhouse gases and it *can* be used to provide many of the same services as fossil fuels across all economic sectors. In reality, many complexities are involved in reducing emissions from hydrogen production—let alone eliminating them—and hydrogen may not be able to compete with alternative decarbonization options such as energy efficiency, electrification, and biofuels.

Low-emissions hydrogen production generally falls into three camps:

1. Using clean electricity to split hydrogen from water ($H_2O$) via electrolysis (often called "green" or "renewable" hydrogen).
2. Capturing and storing some or all of the $CO_2$ from processes that produce hydrogen from fossil fuels or biomass (often called "blue" hydrogen).
3. Drilling for "geologic" or "natural" hydrogen in underground deposits.[iii]

"Low-emissions" hydrogen does not have a consistent definition or emissions accounting framework across jurisdictions, but these technologies comprise the viable pathways today to achieve a much lower lifecycle GHG emissions intensity than conventional hydrogen produced from unabated fossil fuels.[12] As it can help decarbonize applications that are relatively more expensive or impossible to electrify, its near-term development is important to decarbonizing global energy systems by 2050. This potential, paired with its economic opportunity and energy security value, has led to policies intended to clean up and expand hydrogen's production and use.

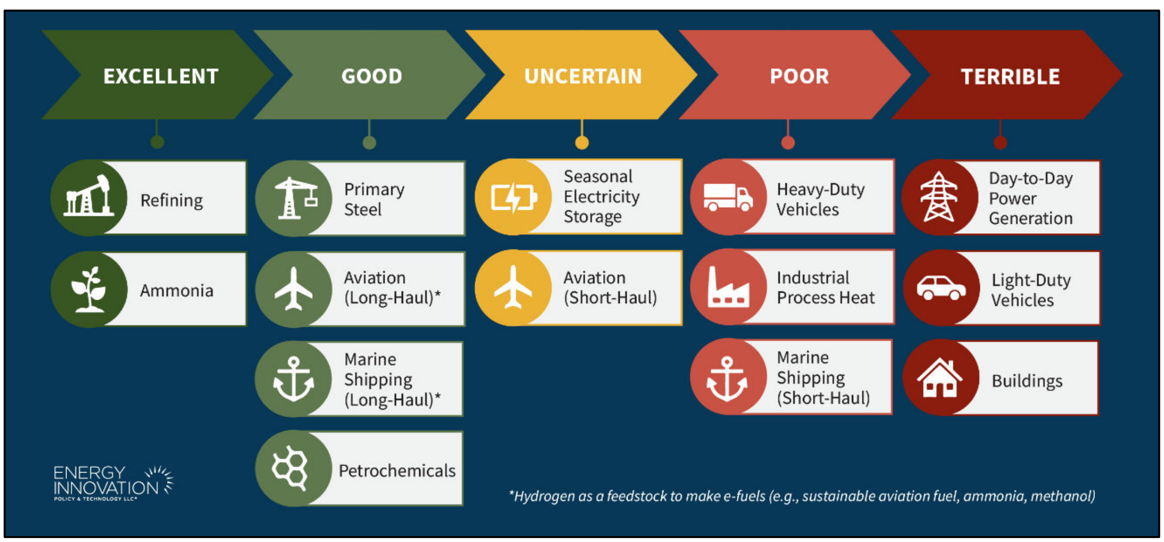
---

[iii] While some jurisdictions have found small deposits of geologic hydrogen, none have located large reservoirs, making it an unproven option at scale.

Ultimately, the long-term viability of low-emissions hydrogen depends on whether the emissions accounting is accurate. Secondary benefits like economic growth and energy security will only manifest long term if hydrogen succeeds in delivering emissions reductions. Policies and investments that grow the hydrogen industry in a manner that does not lead with truly low-emissions production can derail its development as buyers opt for cleaner solutions. For example, policy frameworks that qualify hydrogen electrolyzed from grid power as "low-emissions" can drive production that is highly polluting unless careful safeguards are put in place, and robust demand is unlikely to materialize for a greenwashed product. Upstream leakage from methane-derived hydrogen may create similar concerns. Energy regulators may have limited control over these accounting frameworks, but understanding these fundamentals can help them separate reality from hype when assessing hydrogen production forecasts and regulated companies' investment proposals.

Even within the realm of decarbonization, hydrogen will be more viable in some end uses than others, as it will be competing with alternatives like electrification and biofuels. For example, electrolytic hydrogen looks like a competitive solution for reducing emissions associated with long-haul marine shipping and primary steel production, but not with buildings or ground vehicles.[13] As with hydrogen production policy frameworks, energy regulators likely cannot control demand for hydrogen. However, they should be aware of these dynamics to skeptically evaluate optimistic production and demand forecasts that would impact the need for electric generation, electric or gas infrastructure, and (potentially) regulated hydrogen pipelines. See Figure 3, with Appendix B offering more background on hydrogen for interested readers.

***Figure 3. Electrolytic hydrogen's competitive prospects for decarbonization***

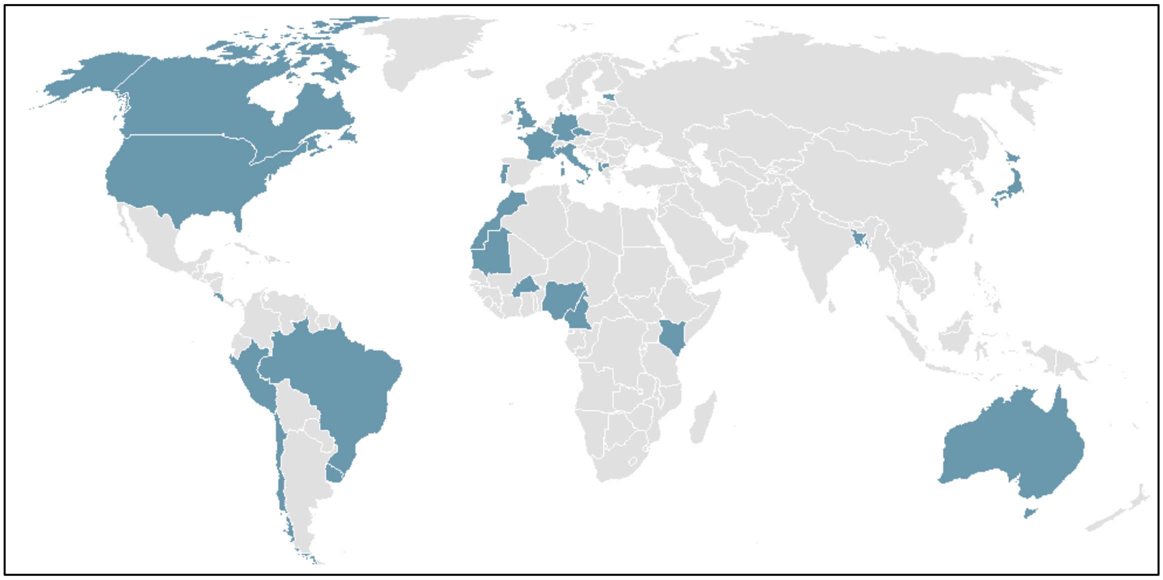



*This graphic presents the results of a broad assessment of where electrolytic hydrogen is likely or unlikely to be competitive with alternative decarbonization technologies like electrification and biofuels. Even "terrible" applications may see rare exceptions in some jurisdictions or* *circumstances, but as a general rule, hydrogen will not be a financially viable option. In some cases, the ranking represents a weighted average—for example, for industrial process heat, electrolytic hydrogen may have viable applications in high-temperature applications but fewer competitive opportunities for serving low- and medium-temperature needs. See Energy Innovation's "Hydrogen Policy's Narrow Path: Delusions & Solutions" paper for more detail.*[14]

## RETA workshops on hydrogen regulation

To help energy regulators prepare to make decisions concerning hydrogen, Energy Innovation partnered with RETA to convene 79 regulators from 37 jurisdictions (including 28 countries across 6 continents) in two workshops. The workshops—held in October and December of 2024—involved summarizing expert research, facilitating exchange among regulators in different stages of hydrogen industry development, and assessing regulatory resource needs across diverse geographic, legal, and economic contexts.

***Figure 4. Hydrogen workshop participants by country***



Participant regulators came from very different places—some were well down the path of evaluating specific hydrogen proposals from natural gas and electric distribution companies, while others had not even started. One clear variable was the type and ambition of domestic climate policy. Some policies directly support the development of hydrogen infrastructure, such as through production subsidies, requirements for industries to use certain volumes or shares of hydrogen, or planning for hydrogen pipelines or export. Policy can also indirectly incentivize the use of hydrogen, such as through carbon pricing mechanisms, GHG reduction requirements, or technology standards.

For example, the EU's Carbon Border Adjustment Mechanism—which sets tariffs on carbon-intensive products—pressures industries to reduce their emissions, including by swapping fossil fuels or emissive chemical feedstocks for low-emissions hydrogen. Separately, clean electricity or heat standards set targets to directly reduce electric and natural gas network companies' emissions, with hydrogen often discussed as a potential option.

Energy regulators' purview also ranges widely across jurisdictions. Most regulators oversee at least monopoly electric network companies and the markets in which they participate. Electrolysis is a primary means of producing low-emissions hydrogen, and regulators have to assess electrolyzers' load growth, as they are massive electricity users. Regulators also need to assess other speculative large demands like data centers and make decisions about grid investments to support highly uncertain demand. Where natural gas service exists, regulators also likely regulate the transport, distribution, storage, and potentially import/export of this fuel, which may be used for hydrogen production or be replaced by hydrogen in some applications downstream.

However, great variation exists in regulatory scope between jurisdictions. For example, some regulators may have a relatively narrow mandate to ensure safety of hydrogen pipelines, while others may be tasked with defining what constitutes "low-emissions" hydrogen. Regardless of these differences, regulators are increasingly being asked to assess hydrogen as governments and companies seek to grow its production and use.

The workshops made clear that regulators are largely in a reactive mode, constantly updating and revising their assumptions and research on hydrogen due to rapidly-changing policy and investment landscapes. Despite this uncertainty, hydrogen investments are being made today, and regulators are seeking to make "least regrets" decisions. There is a need to develop proactive, holistic approaches to balance the many economic and policy interests when faced with government directives or industry proposals to grow low-emissions hydrogen—and, if possible, to share analysis with policymakers to help them set targets that are more in tune with energy system realities. This paper is intended to help regulators navigate these hydrogen-related dynamics in their jurisdictions.

### Preview of subsequent sections

The following sections of this paper illuminate the core regulatory domains in which energy regulators are likely to confront hydrogen, including coverage of key regulatory questions and priorities; summarize other important issues where hydrogen will arise that may fall outside of energy regulators' decision-making purview but represent important opportunities for inter-agency coordination; and offer a brief conclusion. Appendix A provides a resource library to help interested readers find relevant materials for more in-depth analysis, and Appendix B offers additional background reading on hydrogen.

# IMPLEMENTING HYDROGEN POLICY THROUGH A REGULATORY LENS

This paper is intended for energy regulators, which we define as regulators overseeing the affordable, reliable, and safe provision of energy services (with an emphasis on regulating natural monopolies), rather than protecting the public from negative and avoidable pipeline safety and pollution impacts. This paper starts from the premise that the reason for and purview of regulation will not be uniform across jurisdictions. While some energy regulators' roles overlap with pipeline safety, environmental, and other areas of regulation, RETA is an organization dedicated to energy regulation.

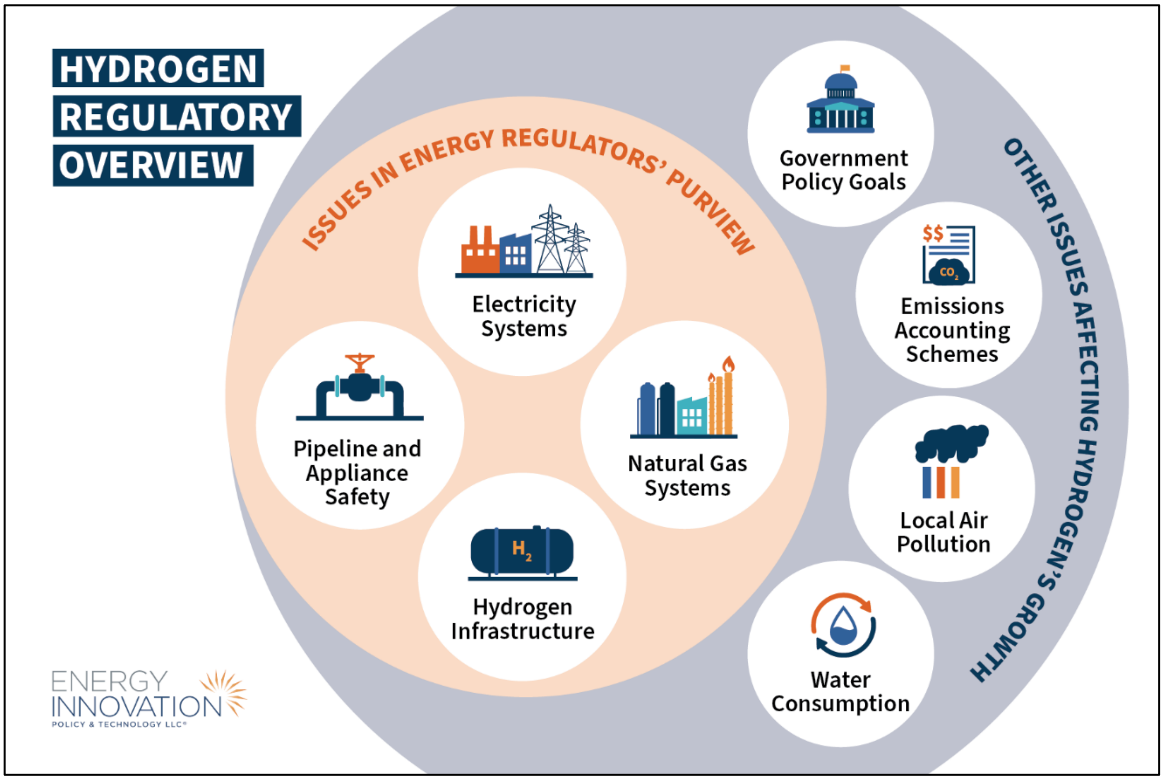
Due to impacts on safety, pollution, permitting, water, and trade, there are multiple regulatory jurisdictions over the same hydrogen molecule and infrastructure. In practice, energy regulators may face overlapping mandates with other regulatory agencies that incorporate hydrogen from their own perspectives of use. For this reason, joint work is necessary to define and coordinate the use of hydrogen for different purposes, taking into account the respective jurisdictions. We limit this section to matters of direct energy regulation as well as pipeline and appliance safety given the latter's relevance to energy regulators' mandate of ensuring safe service, and we summarize trade and environmental impacts in the subsequent section of this paper.

Energy regulators will likely first interact with hydrogen in the context of regulating existing energy companies—primarily electricity and natural gas networks. Regulated companies will encounter hydrogen as a large electricity and natural gas user, as well as an option for providing electricity, heat, and feedstocks. In a high-hydrogen production and delivery scenario, hydrogen pipeline networks and markets may exhibit characteristics such as concentrated market power that justify more direct regulatory oversight similar to natural gas pipeline networks that serve many end-users. And the transportation, storage, and use of hydrogen pose significant safety risks because it is a tiny molecule and volatile gas prone to leakage.

In the following sub-sections, we highlight a few questions regulators might pose to their staff and regulated entities, offering some initial context and guidance for each. We also share priorities for further investigation as regulators proactively plan for domestic policies promoting—and industry interest in—low-emissions hydrogen.[iv]

[iv] The development of a low-emissions hydrogen industry also has significant implications for the potential production, transportation, storage, and use of other molecules, such as carbon dioxide (i.e., for hydrogen produced from natural gas with CCUS) and derivative chemicals like ammonia (for which some jurisdictions are exploring expanded uses like power generation). Regulators may need to think through questions involving this extended family of molecules to better understand factors affecting the hydrogen industry's trajectory. However, these molecules fall outside the scope of this paper.

*Figure 5. Overview of hydrogen regulatory issues*




*While most energy regulators only have jurisdiction over the "issues in energy regulators' purview," they can make smarter decisions on these issues by widening their aperture of awareness to consider—and coordinate with other agencies and authorities on—these "other issues affecting hydrogen's growth" that may fall outside of their direct decision-making power.*

## Interaction with regulated electricity systems

Hydrogen electrolysis[v] requires electricity—and lots of it. Providing hydrogen to match the IEA's NZE Scenario would consume 15 percent of the global electricity supply in 2050, or more than half of all electricity consumed in 2019.[15] Electrolyzers would likely be concentrated in regions with excellent renewable resources that give them a cost advantage as well as in jurisdictions with large industrial bases. However, this projection is highly uncertain. As discussed above, low-emissions hydrogen's primary value stems from its decarbonization potential. Even then, it must compete against other viable technologies—including more efficient electric technologies and other low-carbon

[v] Hydrogen electrolyzers work by passing an electric current through water, splitting the water molecules into hydrogen and oxygen. The hydrogen produced by the electrolyzer can then be used. For a more detailed explanation, see generally, https://bmarkostructures.com/blog/what-are-hydrogen-electrolyzers/.

fuels—that will also play a role in decarbonizing even the more viable use-cases for hydrogen such as steel and petrochemicals.

Regulators are faced with navigating this uncertainty in their oversight of electric network company rates and investment plans, often under mandate to harmonize with industrial or climate policy. Hydrogen electrolysis will impact electricity demand forecasts dramatically. It also has the potential to serve as a large source of flexible, price-responsive demand that can benefit system reliability and reduce costs under the right conditions. Hydrogen electrolyzers could co-locate with renewable energy resources[vi]—ensuring qualification with low-emissions hydrogen definitions, reducing transmission and distribution costs, and securing green premiums for clean energy. Interconnection and electricity pricing policies will heavily influence the location, type, and magnitude of electrolyzer projects. Regulators will have to balance pressure to support hydrogen production via attractive pricing with the impacts such pricing might have on other consumers—as well as the possibility that policy changes could result in stranded assets.

### Regulatory questions

As regulators encounter hydrogen proposals or market impacts within the context of electricity regulation, they will want to consider the following questions:

1. **What role should hydrogen play in storing and supplying energy in a low-carbon power system?**

In jurisdictions with policy requirements to reduce electricity sector emissions, energy companies may look to low-emissions hydrogen as a source of dispatchable energy that can complement variable renewable energy in displacing fossil fuels. Combustion turbine technologies to burn blends of hydrogen and methane—as well as 100 percent hydrogen—are currently in the demonstration phase, as they must manage hydrogen's more challenging combustion characteristics as well as the harmful NOx emissions that form with higher-temperature combustion in air.[16]

Regulators are already seeing proposals for natural gas-fired power plants that promise later conversion to hydrogen blending or 100 percent hydrogen use. However, these proposals risk resulting in high costs, stranded assets, or missed climate targets if the technology—or the availability of on-demand, cost-competitive, low-emissions hydrogen fuel—fails to materialize.[vii,viii] Such proposals may be especially risky if the

---

[vi] At least one regulator participating in RETA's hydrogen workshops indicated co-location is common for current hydrogen development proposals in their country.

[vii] This remains an issue for hydrogen blends with methane, as the former has a lower volumetric energy density. For example, a 50-50 blend of hydrogen with methane would only reduce GHG emissions by 22 percent (assuming the use of zero-emissions hydrogen). See Appendix B for more detail.

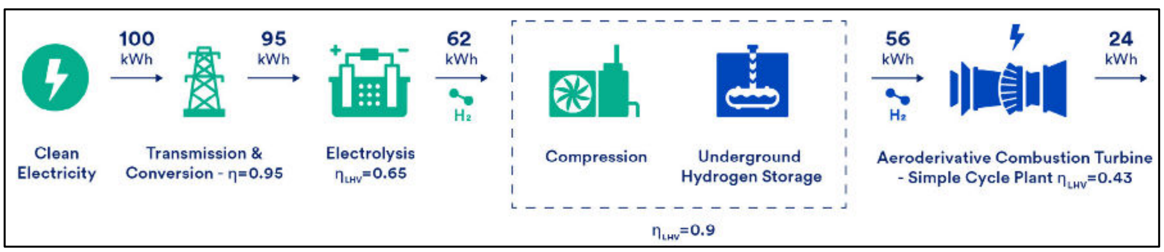
[viii] Per an Agora Industry meta-analysis: "independent research estimates contribution of hydrogen to power generation [as] 0-3% in 2040, 0-6% in 2050." This suggests hydrogen will have a relatively small (if potentially

initial power plants are predicated on running at higher capacity factors, as hydrogen is unlikely to be cost-competitive outside of niche roles (discussed below). Fuel cells can also use hydrogen to produce power, are commercially available, and emit only water vapor—however, they are almost exclusively used today in smaller-scale applications.[17]

Electrolyzers can serve as part of a system to store excess renewable electricity over seasonal or even multi-annual timeframes, with this hydrogen being used to fuel power plants in times of low clean energy availability or help serve industrial end uses that demand year-round supply of feedstocks or fuels. Flexible electrolysis therefore serves as a potential solution for balancing variable output in a high-renewables grid, in conjunction with storage infrastructure, low capacity factor power plants, and industrial hydrogen demand.[18]

However, to the degree electrolytic hydrogen is used for power generation, it is likely to be limited to these seasonal or multi-year energy storage applications.[ix] The roundtrip efficiency[x] of electrolyzing and then generating power from hydrogen is low, returning only 24 to 35 percent of the original electricity (and at best approaching 65 percent with technology improvements).[19] This process cannot compete with renewables like wind and solar when available, and lithium-ion batteries own a substantial roundtrip efficiency advantage for providing intraday storage services.[20]

***Figure 6. System efficiency of electrolytic hydrogen use in power generation in a simple cycle plant***




*Source: Clean Air Task Force.*[21]

Hydrogen presents significant pros and cons for providing seasonal and multi-annual energy storage. On one hand, if hydrogen production rises to serve other sectors, there may be an opportunity to occasionally draw from a common pool to provide power when the grid needs it, with many users sharing infrastructure costs—a dynamic that could reduce the cost and risk placed on electricity consumers.[22] Certain electrolyzer

---

important) role to play in power generation—so energy regulators should be skeptical of outsized requests for "hydrogen-ready" combustion turbines, at least outside of clear seasonal energy storage use-cases (in turn suggestive of very low capacity factors). See: https://www.agora-industry.org/fileadmin/Projekte/2025/2025-04_INT_No-regret-H2/A_IND_Prioritising_hydrogen_WEB.pdf, p35.

[ix] Low-emissions hydrogen produced from fossil fuels with CCUS may also have a limited role in power generation, as to the degree such a hydrogen production method is viable and competitive, it may compete with fossil fuel power generation with CCUS, which skips the intermediary step of making hydrogen.

[x] "Roundtrip efficiency" represents the share of electricity put into storage (i.e., via charging a lithium-ion battery or producing electrolytic hydrogen) that is later usable as electricity. A high roundtrip efficiency means relatively little electricity is lost as a result of storage and reconversion into electricity.

technologies are also highly flexible and could provide reliability services by quickly ramping production up or down to respond to grid needs.

On the other hand, the low roundtrip efficiency of electrolyzing hydrogen and then combusting it for power, lack of hydrogen transportation and storage infrastructure, competition with other technologies seeking to use low-cost clean power, and local air pollution risks from hydrogen combustion make betting on hydrogen as a dispatchable power generation solution in future planning risky and potentially costly.

2. **How will the production and demand for hydrogen affect the need for electrical infrastructure?**

Electrolysis is projected to be a dominant means of producing low-emissions hydrogen in a low- or zero-carbon energy system, although when and if low-emissions hydrogen demand will materialize is still highly uncertain. For example, the EU's hydrogen strategy targets 10 MMT of renewable hydrogen production by 2030, which would require at least 40 gigawatts (GW) of hydrogen electrolyzers—and likely much more.[xi,23] Such deployment, while now highly unlikely in this timeframe, would require an increase in EU electricity generation of 15 to 20 percent relative to total 2023 generation.[24]

This strong signal from EU leadership, combined with a relatively tepid market response (only 385 megawatts of electrolyzers deployed by mid-2024), may leave regulators perplexed.[25] How should regulators view investments in power generation and transmission infrastructure to support this goal? Moving too quickly risks putting costs on existing consumers to support load growth that never materializes.[xii] Moving too slowly risks stifling the market. Regulators can bring consumer and industry voices to the table to understand if there are least-regrets infrastructure investments that can remove barriers to hydrogen development without raising costs on existing consumers, while emphasizing the practical risks and realities to policymakers who are setting hydrogen production goals.

3. **How should electricity rates be designed to meet policy goals for hydrogen, promote flexible hydrogen electrolysis, and allocate costs fairly?**

Rate design and cost allocation go hand in hand with infrastructure planning. To achieve growth in clean electrolytic hydrogen, electrolyzers need access to power that is low-cost, abundant, and carbon-free. Because they are energy intensive, electrolyzers need access to low-cost power to reduce the per-unit cost of hydrogen. They are also capital intensive and will reduce unit costs if they can operate in more hours of the year.

---

[xi] At an efficiency of 50 kilowatt-hours per kilogram of hydrogen operating non-stop, producing 10 MMT of hydrogen would require closer to 57 GW of electrolyzers. Renewable hydrogen—that is, using new, deliverable, hourly-matched clean electricity—is unlikely to run non-stop, implying a need for even more electrolyzers to meet this target.

[xii] In some respects, new electrolyzer demand parallels new data center demand—regulators can learn from peers' efforts on data centers to address the risk of load growth that never materializes via new tariff designs. See generally: https://www.swenergy.org/data-centers-power-needs-and-clean-energy-challenges/

And they need some way to rationally claim the "clean" electricity attributes associated with low-emissions hydrogen requirements (discussed in the next section). Achieving low-cost, low-emissions hydrogen production is an essential part of realizing governments' hydrogen policy goals.

Ensuring all users pay fairly for the infrastructure and delivery costs of service is the other side of this equation of access to low-cost power. Serving a large user involves both new power sources and transmission and distribution (T&D) infrastructure. In some places, the fixed cost component of rates may be larger than the generation component, challenging electrolyzer project economics. Regulators face difficult choices on how to fairly allocate the cost of service between large new loads and existing customers, especially under government policy frameworks promoting production of low-cost, low-emissions hydrogen.

For hydrogen electrolysis, power prices can make or break project economics, so they would like to avoid these T&D upgrades and charges and consume wholesale power when it is cheapest and cleanest. Electrolyzer technologies vary in the flexibility of their operations (e.g., ramping speed, minimum operating thresholds, startup/shutdown times)—more flexible technologies reduce their burden on the grid and enhance rather than detract from system reliability.[26] For example, more flexible hydrogen producers may be able to reduce consumption during the times of high demand that would generally require additional T&D capacity, thereby reducing the overall cost of electricity in general rates. They may also be able to respond more readily to changes in solar and wind output, reducing reliance on other aspects of the power system to respond and maintain stable frequency. Regulators should design rates to incent this flexible technology deployment and operation—hydrogen electrolyzers (and other flexible large loads) can respond to price signals to reduce grid impacts and access lower cost rates without burdening existing customers with higher grid costs.

Some rate and market design choices may help hydrogen electrolysis access more economical power rates and evolve harmoniously with the growth in variable wind and solar resources while reducing the need for T&D upgrades.[xiii] For hydrogen electrolyzers and other large loads, regulators can help promote deployment of more flexible technologies by providing price signals to avoid consumption when the grid is stressed. For example, where wholesale markets exist, regulators can pass through the cost of real-time wholesale rates to large, sophisticated end-users. Regulators can also incent co-location and self-consumption with renewable generators by expressly permitting large loads direct access to these arrangements.[xiv] They can also ensure inflexible

---

[xiii] See generally: https://www.irena.org/Innovation-landscape-for-smart-electrification/Power-to-hydrogen/Smart-hydrogen-production-kit.

[xiv] Per IRENA on self-consumption: "Co-located electrolysers and renewable power plants could operate together in isolation without a grid connection, or a grid connection could be added to increase the overall system flexibility and provide services for the power system, such as acting as a 'dispatchable power plant'. . . . Co-locating electrolysers with onshore or offshore renewable power plants can substantially reduce costs

electrolyzers pay their fair share by encouraging power companies to offer rates that include peak-coincident demand charges to reflect the fixed infrastructure costs that would be necessary to serve these consumers when demand is highest.

### Regulatory priorities

To help develop a proactive approach to hydrogen that provides timely access to fairly priced power, protects all consumers, and enhances system flexibility, we recommend the following priorities:

1. Engage with electricity distribution companies, industry, and consumers to better understand the potential impacts of hydrogen electrolysis on the electricity system, assess the reasonableness of electricity demand projections, and discern how to protect consumers while meeting this demand.
2. Develop electricity prices and interconnection schemes that encourage flexible electrolyzer operations that align with carbon goals, promote low-cost hydrogen production, minimize new infrastructure, and protect existing customers.
3. Study the technology set, including hydrogen, that could provide dispatchable capacity and seasonal storage needs in a low-emissions electricity system.

## Interaction with regulated natural gas systems

Reforming methane gas and capturing the byproduct $CO_2$ is the other main way to produce low-emissions hydrogen. The IEA NZE Scenario forecasts such hydrogen production would require 28 percent of projected global natural gas demand (246 billion cubic meters) in 2050.[xv,27] However, it also forecasts that global natural gas demand will fall by nearly 80 percent relative to today's consumption due to substantial reductions in natural gas in power generation and industry and its near-elimination in buildings and transport.[28] Again, the quantities of total natural gas demand and gas used for hydrogen production are highly uncertain—for example, the APS forecasts natural gas demand will only fall by 40 percent by 2050, with hydrogen production making up less than 10 percent of this demand.[29] However, the IEA's analysis suggests hydrogen production will be a major factor affecting the need for natural gas pipeline, compression, and storage infrastructure in a low-carbon future.

---

and improve the business case for projects. This can reduce power losses due to long-distance electricity transmission or help avoid such losses, reduce network charges and help avoid the costs of building transmission lines." See: https://www.irena.org/Innovation-landscape-for-smart-electrification/Power-to-hydrogen/22-Co-locating-electrolysers-with-renewable-generators-onshore-and-offshore.

[xv] The value for natural gas demand used for low-emissions hydrogen production includes only "merchant" hydrogen (produced for sale to other parties), excluding hydrogen production for use on site. As the latter can be substantial, the actual natural gas demand implicated by low-emissions hydrogen production could be much larger than described here

Hydrogen may also impact the natural gas system in countries with natural gas distribution networks. For example, jurisdictions including Canadian provinces, the United Kingdom, and U.S. states have already seen industry-led proposals and active initiatives to either blend hydrogen into existing natural gas networks or reuse those networks for hydrogen distribution.[30]

However, substantial evidence exists that hydrogen blending will not meaningfully reduce GHG emissions from the natural gas system nor be able to scale to meet buildings' heating needs in a cost-effective, safe, and timely manner—at least relative to competing pathways like switching to electric appliances or thermal energy networks.[31] Regulators should recognize gas network company incentives to maintain traditional business models (i.e., distribution of gaseous fuels) when reviewing company-driven analyses supporting hydrogen blending or "hydrogen-ready" infrastructure over less costly actions that may reduce a company's asset base.[32]

### Regulatory questions

As regulators encounter hydrogen proposals or market impacts within the context of natural gas network companies and network regulation, they will want to consider the following questions:

1. **How will demand for low-emissions hydrogen affect natural gas demand?**

Low-emissions hydrogen demand is highly uncertain. Optimistic industry forecasts run the gamut, but even with generous policy support, starting an industry from scratch is easier said than done. Even more uncertain is which production technologies will win the race to supply most of a clean economy's hydrogen needs. In natural gas-rich regions, methane-based hydrogen production with CCUS could be a lifeline to a gas industry the prospects of which may dim dramatically in a low-carbon economy. But this depends on the technology's viability and competitiveness compared with electrolysis and potential emerging options like geologic hydrogen. Currently, approximately 15 facilities around the world make hydrogen from fossil fuels with CCUS, producing 0.6 MMT of low-emissions hydrogen—and these depend heavily on government incentives.[33]

Low-emissions hydrogen can displace natural gas demand through hydrogen's use while also increasing natural gas demand through hydrogen production. Low-emissions hydrogen has potential to replace natural gas for providing heat to industry, power plants, and other end uses alongside electrification, but it faces significant economic hurdles. Regulators trying to parse the wisdom of repurposing existing gas pipelines or authorizing new hydrogen pipelines would benefit from gathering facts from industry, researchers, and other stakeholders on these complex dynamics. What indications show demand for hydrogen as a heating source will materialize, and in which sectors and industries? How do the economics of methane-derived low-emissions hydrogen compare with electrolytic hydrogen in a given jurisdiction, and how much competition does this hydrogen face in the market?

2. **How should regulators and natural gas companies plan for hydrogen production and use?**

The amount of hydrogen and natural gas demand feeds into complementary questions about future needs for infrastructure to serve end-use customers. A primary question for regulators will be how and if existing pipelines can be repurposed to transport hydrogen. Research done for the European Union Agency for the Cooperation of European Regulators (ACER) and its member countries indicates it is likely less expensive to retrofit existing natural gas pipelines than building new dedicated hydrogen pipelines for high-volume transportation, but there is high uncertainty.[34]

The consideration of whether to repurpose a pipeline involves planning. At what point is natural gas demand likely to fall enough to justify repurposing the pipeline? What additional expenses would best reduce risks of metal pipeline embrittlement? How should compression infrastructure be updated to reflect the lower volumetric energy density of hydrogen? Who should be allowed to own and operate this infrastructure, and how much should they pay the incumbent network company for it (discussed in the following sub-section)?

In many jurisdictions, questions center not around full repurposing, but rather the capacity of existing natural gas infrastructure and its end-users to accept a blend of hydrogen. In some places, this may be a transition strategy with fewer GHG emissions or less dependence on gas imports in mind. In such cases, regulators may benefit from examining blending proposals with long-term goals at the forefront. For example, is it prudent to allow blending at presumably safe levels when safety or customer tolerance—for any of the wide range of appliances and equipment on the network—are highly questionable at higher shares of hydrogen? With some natural gas network companies already pursuing hydrogen blending or even full hydrogen use to decarbonize buildings, regulators can make wiser judgments by asking whether such plans are safe, feasible, and cost-effective, as well as whether eventual dead-ends (e.g., at certain blends) put the timely achievement of deeper GHG emissions reduction goals at risk.

The U.S. state of Massachusetts provides one example of how to develop evidence to answer these questions. In December 2023, Massachusetts' Department of Public Utilities developed a forward-looking regulatory framework on how to best reduce natural gas system emissions under state laws requiring deep GHG emissions reductions. The Department of Public Utilities order found that "while hydrogen may play a role in some hard-to-decarbonize sectors of the economy, it is unlikely to be considered as a primary fuel source for home heating" due to uncertainty around its actual emissions intensity, cost, technical feasibility, and availability.[35] As a result, network companies in Massachusetts are encouraged to evaluate non-gas alternatives like efficiency and electrification and avoid dead-end expenditures on decarbonizing fuel sources. Regulators in the U.S. state of Colorado, as well as several independent analytical bodies in the UK, reached similar conclusions for their jurisdictions.[36] While isolated cases exist for blending higher shares of hydrogen into natural gas networks, these exceptions are due to legacy infrastructure built to manage manufactured gas[xvi] to serve industrialized island jurisdictions.[37]

### Regulatory priorities

To help develop a proactive approach to natural gas regulation and planning with hydrogen in mind, we recommend the following priorities:

1. Engage with natural gas distribution companies, industry, and consumers to better estimate how low-emissions hydrogen demand will impact natural gas demand and prices—via the use of natural gas for hydrogen production, the use of repurposed natural gas infrastructure for hydrogen delivery, and the displacement of natural gas from hydrogen's use downstream.
2. Examine the relative safety, cost, environmental, and feasibility implications of using hydrogen to decarbonize different heating needs (e.g., buildings, industrial processes), placing a heavy burden of proof on industry proposals and learning from other jurisdictions' assessments. Work with stakeholders to compare hydrogen blending or reusing natural gas infrastructure with the full range of alternatives including clean electrification, biofuels, thermal energy networks,[xvii] and other solutions.
3. Assess the viability and cost of repurposing natural gas pipelines for hydrogen transportation. Where hydrogen production and demand are likely to increase and require transportation, assess whether there are existing pipelines particularly well-suited for reuse and how cost recovery for reused assets would be treated. Begin to incorporate these decisions into gas system planning.

## Regulatory oversight of hydrogen infrastructure

Regulation becomes necessary when unregulated private industry behavior does not align with the public interest. In the case of energy systems, the role of different regulators—which can vary from place to place—is usually spelled out by policymakers. For example, certain regulators may deal with pipeline safety, another with air quality, another with efficiency, and another the oversight of natural monopolies like gas and electricity networks.

---

[xvi] I.e., coal or naphtha processed into a mix of methane and hydrogen.
[xvii] Thermal energy networks "heat and cool buildings at the campus, block, or neighborhood scale with non-combusting, non-emitting thermal sources such as geothermal energy or waste heat using a network of interconnected underground pipes. See generally: https://www.ilr.cornell.edu/sites/default/files-d8/2024-12/understanding-thermal-energy-networks.pdf

For energy regulators currently overseeing electricity and gas networks (the audience for this paper), questions quickly arise around whether and to what extent hydrogen production, transportation, and storage fits within the regulated activities of existing electricity or gas distribution companies. For example, an incumbent natural gas provider may seek to gradually take on the role of hydrogen distributor, particularly if it is permitted to blend hydrogen into its existing natural gas pipeline system. Likewise, a vertically integrated electricity company could advocate for the inclusion of hydrogen electrolyzers, dedicated generation to supply those electrolyzers, hydrogen storage infrastructure, and hydrogen-fueled power plants into its monopoly.

At some point, hydrogen production, storage, transport, and use may form a network (including by subsuming part or all of existing networks) that exhibits similar characteristics that required the economic regulation of natural gas monopolies, placing the energy regulator closer to the center of the hydrogen industry's future. Whether something is a "natural monopoly" depends on a few characteristics, which are summarized in an EU ACER and Council of European Energy Regulators (CEER) paper investigating hydrogen regulation. Their doctrine applies the following conditions: "control of the facility by a monopolist; the competitor's inability to practically or reasonably duplicate the essential facility; abuse of dominant position in the form of denying competitors access to the facility; [and] general competition law [being] insufficient to address the possible abuse of dominant position."[38]

In most jurisdictions, hydrogen is far from exhibiting natural monopoly characteristics today. Hydrogen pipelines scarcely exist and have not formed mature networks outside of local petrochemical facilities or campuses. New hydrogen production and pipelines are likely to begin at a business-to-business level, with demand for low-emissions hydrogen lagging behind ambitious policy goals. However, in places with ambitious hydrogen policies, there are already proposals to plan and finance expansive hydrogen networks in concert with industry decarbonization plans. Regulators should not wait for these questions to emerge—there is an opportunity now to consider the scope of activities existing monopolies can undertake, develop an adaptive approach that periodically reexamines the scope of regulatory oversight appropriate to hydrogen infrastructure, and examine the long-term market and regulatory structures that best align with the public interest.

### Regulatory questions

As regulators consider the growth of hydrogen infrastructure in their jurisdiction, they will want to consider the following questions:

1. **What is the regulatory jurisdiction over hydrogen infrastructure?**

In general, few jurisdictions have clear statutory policies or established regulations governing hydrogen development. Without this explicit authority, regulators may have difficulty taking a proactive approach to developing good regulatory practice around these important public interest issues. There is an opportunity for regulators to call policymakers' attention to the limits of their regulatory authority in protecting the public interest. Likewise, policymakers have an opportunity to examine existing laws and clarify the roles and responsibilities of different regulators over the production, transportation, storage, and sale of hydrogen.

In the absence of clearer guidance, regulators can take a proactive approach to examining this question: under what conditions should hydrogen infrastructure be treated as a part of an existing or new natural monopoly worthy of regulation? Under what conditions should it be allowed to evolve without any price regulation? Historical justification to regulate existing networks—especially pipelines—will reveal conditions to watch for and enable regulators to create principles and practices that cultivate a hydrogen industry that aligns with the public interest.

Proposals to pilot including hydrogen into existing network company business models should be evaluated for their near-term impacts, as well as whether they are aligned with a long-term vision for how the hydrogen industry should evolve. For example, perhaps the regulator determines it is not economical or safe to blend hydrogen into the gas system for building heat but there is a policy remit and growing demand for hydrogen for large industrial users. What is the role of the existing natural gas pipeline provider for retrofitting pipelines and providing service to hydrogen end-users? Would wholesale transactions between producers and large consumers require network regulation, or would unregulated parties reach better outcomes while holding existing residential gas customers harmless, such as in industrial cluster designs?[39] At what point does a hydrogen economy exhibit characteristics that require greater economic regulation akin to the existing regulatory framework around the gas pipeline network?

The EU's 2024 gas decarbonization directive explores many of these issues and can serve as a model for jurisdictions that have policies that strongly support development of low-emissions hydrogen.[40] The policy framework establishes rules around third-party access to hydrogen networks, delegates authority to national regulatory bodies for hydrogen network regulation, establishes an international network of hydrogen network operators, and creates rules for gas network companies' engagement in hydrogen production and transmission. It requires network operators to conduct long-term network plans and coordinate with electricity and gas planners on infrastructure planning. It also establishes conditions under which dedicated production and pipeline facilities for single industrial uses could be exempt from network regulation. As another example, a similar examination from the Canadian province of British Columbia's energy regulator also sets principles for the scope of regulatory jurisdiction over hydrogen.[41]

2. **How should the costs and ownership rights of hydrogen infrastructure be allocated, especially if it was once part of the natural gas network?**

Some regulation of hydrogen infrastructure may arise from its reuse of natural gas infrastructure that is already subject to cost-based regulation. In this case, regulators already confront monopolistic incentives. Regulators should examine whether the incumbent natural gas network company should own and operate hydrogen infrastructure, then proactively address how to allocate costs for this infrastructure when it is no longer transporting natural gas.

For example, if a gas pipeline is converted to transport hydrogen, there are multiple interpretations of a fair price for a natural gas asset that may not have been fully depreciated. Furthermore, the incumbent natural gas network company may attempt to deal with its own subsidiaries in this transaction, raising anti-competitive concerns. If there is gradual blending, the regulator may have to decide the point at which a blend of hydrogen and natural gas no longer constitutes natural gas service. What does this trigger in terms of that asset's treatment for cost recovery as part of the entire asset base? Separately, the permitted conversion of a natural gas pipeline for hydrogen transport may lead to a stranded asset if hydrogen demand does not materialize. All of these issues implicate how regulators can protect existing natural gas consumers.

The EU's 2024 gas decarbonization directive provides an example of how policymakers and regulators are dealing with these questions today. Within its gas decarbonization directive, the EU requires gas and hydrogen distribution companies "shall be independent at least in terms of its legal form, organization and decision making," but they do not rule out joint ownership.[42] The directive also requires state regulators to "ensur[e] that there are no cross-subsidies between transmission, distribution, hydrogen transport, natural gas and hydrogen storage, LNG and hydrogen terminals and natural gas and hydrogen supply activities."[43]

### Regulatory priorities

In 2021, ACER/CEER recommended the EU take a gradual and adaptive approach to the regulation of hydrogen networks in line with market and infrastructure development, which periodically monitors the market for monopolistic behavior. Its four principles—that then informed its more comprehensive gas decarbonization directive finalized in 2024—formed the basis of the following regulatory priorities:[44]

1. Clarify regulatory principles for hydrogen regulation from the outset, and define the limits and terms for incumbent monopoly businesses to participate.
2. Foresee temporary regulatory exemptions for existing and new hydrogen infrastructure developed as business-to-business networks.
3. Value the benefits and costs of repurposing natural gas assets for transporting hydrogen, and verify those cost estimates in any demonstration projects.
4. Avoid cross-subsidization between the natural gas and hydrogen networks when natural gas assets are repurposed for hydrogen transport.

These principles can serve as a model for other regulators beginning on the journey of regulating hydrogen. Taken together, they represent an adaptive framework, which in its implementation creates clear conditions that would trigger regulatory oversight and periodic reviews of the regulatory framework. This approach allows oversight to evolve alongside the hydrogen market's development while providing regulatory certainty.

### Pipeline and appliance safety

Hydrogen's unique chemical properties make it more challenging to safely manage than methane. It has a high propensity for leakage as it is the smallest molecule and can "embrittle" metal pipelines by permeating and creating fissures in their walls. It is undetectable by human senses, combusts more readily in a wider range of mixtures with air, has a faster flame speed that can travel back through pipes to damage equipment, and burns hotter with a barely-perceptible flame.[xviii,45] Hydrogen also has a very low volumetric energy density and requires extremely low temperatures to liquefy, which brings its own set of operational risks for hydrogen storage.[xix] Finally, hydrogen's transportation can involve carriers or intermediaries like ammonia—such chemicals may fall outside regulators' purview (and are not in scope for this paper), but regulators may similarly need to be cognizant of their safety considerations.[46]

Chemicals industries have safely been producing, compressing, transporting, storing, and using hydrogen for decades, so its challenges can be overcome. However, this has largely been limited to open-air industrial parks with tight safety standards, rigorous oversight, and components specifically designed to manage hydrogen.[47] To the degree regulators oversee energy companies' development and operations of purpose-built hydrogen pipelines for production and use in industrial settings—including new markets like e-fuels for aviation and marine shipping—they will have a rich database of existing codes and standards from which to draw.[48]

However, regulators may encounter hydrogen in the context of transporting, storing, or using it in infrastructure that was not purpose-built for hydrogen, such as natural gas pipelines and consumer appliances. This introduces at least two categories of heightened safety risks. First, hydrogen blending can cause the degradation of pipelines, leading to leaks or disastrous ruptures.[49] Natural gas pipelines are already somewhat leaky—with extensive measurements confirming this—and hydrogen would exacerbate this given its much smaller size.[50] Second, hydrogen blending involves the loss of some of the strict technical oversight, safety mechanisms, and design characteristics that are employed in industrial parks (e.g., better ventilation through above-ground, open-air pipes). New risks are introduced as hydrogen moves from highly specialized campuses to a distributed network involving heavily populated public spaces, buildings with enclosures where hydrogen leaks can accumulate, and

[xviii] While not related to safety, hydrogen also has a climate-warming impact of approximately 37 times that of carbon dioxide over a 20-year period, meaning leakage can erode its GHG emissions reduction value. See: https://www.nature.com/articles/s43247-023-00857-8

[xix] Hydrogen's low volumetric energy density means that blending it with methane will deliver a lower-than-expected GHG emissions reduction benefit—e.g., a 20 percent blend of hydrogen with methane will only reduce emissions by approximately 7 percent (assuming zero-emissions hydrogen). See Appendix B for more.

consumer-facing appliances and equipment that put the public in proximity to hydrogen fuel.

While governments and industry have tested the degree hydrogen can mix with natural gas, repurpose natural gas infrastructure, and work with new or existing consumer appliances, regulators who opt to entertain blending must acknowledge these risks—even if they don't have direct regulatory oversight—to protect people from explosions and damage to appliances. These concerns implicate the need for new or updated design standards, safety monitoring and inspections, substantial financial reserves and insurance, and decommissioning funds.

### Regulatory questions

As regulators seek to maintain a high standard of safety with the introduction of hydrogen, they will want to consider the following questions:

1. **If regulated energy companies seek to build hydrogen infrastructure (or repurpose natural gas infrastructure), are they prepared, able, and properly motivated to follow all relevant safety standards across the value chain?**

There are approximately 5,000 kilometers of hydrogen pipelines in operation globally today—far below the more than 1.4 million kilometers of natural gas pipelines worldwide.[51] These hydrogen pipelines are heavily concentrated in the U.S. Gulf Coast and northwest Europe.[52] They have also been largely developed and operated by private companies for industrial use, rather than by energy distribution companies that interact with and potentially serve residential and commercial users.

Thus, while there is deep experience to draw from—as well as groups and standards organizations working to make information on safety more accessible—the vast majority of energy distribution companies are not yet equipped to oversee, develop, or operate hydrogen infrastructure. In particular, regulators will want to ensure such infrastructure is complete with leak and fire detection systems, proper ventilation, and other measures to protect against explosion risks, as well as processes in place for emergency response.

Regulators should also be aware of hydrogen purity considerations. For example, hydrogen purity can vary based on systems employed (e.g., using geologic caverns for storage can introduce contaminants), but certain end uses like fuel cells require very high purities to avoid damaging equipment. Purity standards might be outside of energy regulators' direct purview, but they affect the prudence of energy companies' proposed investments.[53]

2. **Under what conditions can hydrogen be safely blended into the natural gas T&D systems and used by existing end-use equipment?**

As discussed in prior sections, regulators should first consider hydrogen blending on its merits. For example, would hydrogen blending be a reliable, safe, and cost-effective alternative to the status quo or (where emissions reduction targets exist) other options like electric technologies and biofuels? Do its questionable benefits outweigh its widely-documented risks?[54] For jurisdictions with deep decarbonization goals, would success with low hydrogen blends set up a path to a zero-emissions system, or should they pursue more cost-effective and enduring solutions from the start?

If regulators do allow such companies to explore hydrogen blending, they should at minimum ensure natural gas T&D pipelines are suitable for such activity—including by requiring network companies to conduct all relevant assessments. They should also be aware of the state of consumer appliances or industrial equipment being served by this network—or rather ensure that network companies' hydrogen usage will not drive an increase in safety or performance issues downstream—and consider the potential of varying hydrogen tolerances from interconnected neighbor jurisdictions.

While the precise limits depend on a range of factors—such as pipelines' materials and age—in general hydrogen can be safely blended only up to 5 to 20 percent by volume with natural gas in existing gas infrastructure following targeted upgrades and retrofits.[55] However, even these small blends require extensive system testing to prevent hydrogen from compromising any part of natural gas companies' extensive networks and the end uses they serve. For example, liquefied natural gas and compressed natural gas end uses require high methane purities and have been shown to limit or otherwise complicate hydrogen blending initiatives.[56] Regulators should also consider whether hydrogen blending can play a narrower yet safer role, such as by blending hydrogen at the facilities using it (e.g., power plants, industrial sites) rather than into the pipeline network.[xx]

### Regulatory priorities

To ensure investment in hydrogen infrastructure or fuel does not compromise safety, we recommend the following priorities:

1. Establish and update natural gas and hydrogen infrastructure safety standards—with monitoring and enforcement mechanisms—to account for hydrogen's unique characteristics, including for pipelines and storage systems.
2. Learn from industry, standard-setting organizations, and other jurisdictions about hydrogen purity and the limitations of hydrogen blending in natural gas pipelines, consumer appliances, and industrial equipment—including risks related to safety, leakage, gas quality, and compatibility—in order to support broader regulatory decision-making on hydrogen infrastructure investment.
3. Ensure hydrogen providers and network operators meet high standards of financial reliability, accountability, and performance.

---

[xx] For example, this New York-based demonstration project blended hydrogen with natural gas at the site of the natural gas combustion turbine: https://www.epri.com/research/products/000000003002025166

## COORDINATING ON OTHER ISSUES AFFECTING HYDROGEN REGULATION

In addition to their core responsibilities, energy regulators should be aware of other policies and areas of regulation that will affect the hydrogen industry's future development. For example, hydrogen interacts with government climate and economic policy goals, has varying standards for accounting for the emissions intensity of its production, and affects local air pollution and water use. Awareness of these policy structures and potential constraints will help regulators anticipate a realistic pathway for low-emissions hydrogen's development and protect the public interest. These issues also represent important areas for inter-agency coordination, which can prevent regulatory gaps, reduce compliance costs for regulated entities, and promote a holistic regulatory approach that addresses hydrogen's cross-sector impacts.

### Government policy goals

Governments have developed hydrogen roadmaps and strategies in recent years, setting goals meant to drive legislation, regulation, and investment that support their realization. For example, the EU aims to produce 10 million metric tons per annum (MMTPA) and import an additional 10 MMTPA of renewable hydrogen by 2030; Australia seeks to produce 3 to 5 MMTPA of renewable hydrogen by 2035 and export 0.2 to 1.2 MMTPA by 2030; India hopes to produce 5 MMTPA of green hydrogen by 2030 and up to 10 MMTPA if able to export to other markets; Japan wants to use 3 MMTPA of hydrogen by 2030 and 20 MMTPA by 2050; and Morocco aims to export green hydrogen to help supply the EU's import needs.[57]

However, the degree to which the hydrogen industry will develop to meet these ambitious goals is highly uncertain. The EU has publicly acknowledged it will likely miss its 2030 targets.[58] Meeting the upper range of Australia's 2035 production goal would mean doubling its electricity generation (with this coming all from new clean energy), and its 2030 export goals vary by a factor of six.[xxi] India and Japan's goals similarly exhibit a wide range or depend on costly new hydrogen transportation infrastructure. And Morocco's goals depend in part on the challenge of building an underwater intercontinental hydrogen pipeline to Spain.[59] Overall, the IEA notes a massive gulf between governments' hydrogen production targets (ranging from 35 to 43 MMTPA by 2030) and the demand policies they have put in place (which would drive consumption of less than 7 MMTPA by 2030).[60]

---

[xxi] Australia generated 274 terawatt-hours (TWh) of electricity in 2023. At an efficiency of 50 kilowatt-hours per kilogram of hydrogen, producing 5 MMT of hydrogen would require 250 TWh—a near-doubling of the country's total generation (not including electricity demand from hydrogen compression, transportation, and storage). Source: https://www.energy.gov.au/energy-data/australian-energy-statistics/electricity-generation

High hydrogen production goals that may be disconnected from economic realities and commercial demand can put energy regulators in a challenging position. Regulators' decisions can help achieve progress toward these government policy goals, but their core mandate lies in ensuring affordable, reliable, and safe provision of electricity and natural gas services.

The key factor underlying these risks is to what degree hydrogen buyers will show up in response to hydrogen production and transport infrastructure. Outside of today's limited offtake in refining and chemicals, potential hydrogen buyers are industries facing policy requirements or public pressure to cut climate pollution as well as very tight profit margins. In other words, buyers need high confidence that hydrogen will reduce emissions and be available as a competitively-priced commodity.

On emissions, a disconnect between a jurisdiction's hydrogen production goals and the policies used to achieve them can spell trouble. Hydrogen policies that promote its production with little regard to its actual emissions intensity—such as subsidizing electrolyzed hydrogen without properly accounting for induced grid emissions from electrolyzers' load—could drive a bubble of investment in hydrogen infrastructure that pops due to lack of buyer interest in a dirty product.[61]

On cost, buyers might be willing to pay a limited premium for low-emissions hydrogen if it helps sell more products derived from the hydrogen, or they may need to see policymakers close the price gap with tailored policies that will last. However, hydrogen produced in a given jurisdiction will have to compete with hydrogen produced elsewhere as hydrogen trade networks expand or industries move to where low-emissions hydrogen production is least expensive.[xxii] Different jurisdictions may have competitive advantages, especially with respect to the quality and cost of renewable resources supporting electrolytic hydrogen, as well as the availability of low-cost natural gas and geographies suitable for carbon sequestration. Hydrogen-derived products will also have to compete with other low-carbon technologies to serve end uses that have non-hydrogen alternatives. For example, sustainable aviation fuels can be produced from hydrogen or biofuel-derived compounds. Demand-side policies for hydrogen can provide more certainty for investors, but high production prices risk undercutting political appetite to keep such policies in place.

**Exploratory questions for regulators:**

- Given a jurisdiction's hydrogen goals, how might the industry actually develop under different policy, regulatory, and economic conditions? Are the assumptions that underly these goals being reflected in reality?

---

[xxii] Hydrogen pipelines are generally the lowest-cost method to move hydrogen, so hydrogen prices will be significantly affected by when and where they are developed. Moving hydrogen by marine tanker—whether as liquid hydrogen, ammonia, liquid hydrogen organic carriers, or some other intermediary—is expensive but can enable global trade where exporting countries have substantial hydrogen production cost advantages over importing countries. See Figure 4.4 of: https://iea.blob.core.windows.net/assets/89c1e382-dc59-46ca-aa47-9f7d41531ab5/GlobalHydrogenReview2024.pdf

- How does government policy address uncertainty around demand for hydrogen, including if costs come in higher than anticipated? Can regulators inform policymaker target-setting, reviews, or revisions?
- How can regulators support progress toward domestic hydrogen goals without putting unnecessarily high risk on or shifting system costs to consumers? To what extent should regulators allow regulated companies to recover expenditures from hydrogen-related innovation or pilot projects as a means to grow the industry? More broadly, how much independence do regulators have with respect to ensuring progress toward government policy goals?
- Which other agencies and authorities should energy regulators be coordinating with to guide their collective decision-making on hydrogen?

### Emissions accounting schemes

To the extent hydrogen policy supports emissions reductions, policymakers will inevitably have to determine what qualifies as "low-emissions" hydrogen. Most jurisdictions with low-emissions hydrogen definitions have set emissions intensity thresholds of no more than 4 kilograms of carbon dioxide equivalent per kilogram of hydrogen ($kgCO_2e/kgH_2$)—and often lower in leading jurisdictions like the EU—or approximately 60 percent below that of unabated steam methane reformation.[62] Even then, jurisdictions aiming for climate neutrality will likely need to lower these thresholds over time.[63]

Hydrogen producers must verify they are satisfying a given low-emissions hydrogen definition to receive policy support, such as a production subsidy or credit toward meeting a procurement mandate. Energy regulators may be asked to advise on, establish, or help implement emissions accounting schemes that detail how hydrogen producers must estimate their emissions intensities, with such rules used to judge whether their production meets the threshold.

Designing emissions accounting schemes for hydrogen production that reflect reality is challenging. However, bad designs can make the term "low-emissions hydrogen" a misnomer and lead to substantial greenwashing—they risk subsidizing a net increase in GHG emissions as well as developing a product with few buyers, as companies and importing jurisdictions opt for truly low-emissions alternatives.

For example, electrolyzers trigger the production of electricity at the margin—in most jurisdictions and hours, this will be coal- or natural gas-fired power plants. Accounting for these emissions can bring electrolytic hydrogen's emissions intensity to as high as 40 $kgCO_2e/kgH_2$, or more than 10 times that of most jurisdictions' current low-emissions hydrogen thresholds.[64] Achieving truly low- to zero-emissions electrolytic hydrogen production requires drawing from clean energy in a manner that does not induce significant fossil fuel power generation elsewhere on the power system. However, this use of "additional" clean power can be difficult to prove.

Emissions accounting rules fall on a spectrum. On one end are less-precise rules that credit electrolyzers for any carbon-free electricity that they buy in the market, ignoring induced grid emissions impacts. While these rules are administratively simple, they are very likely to boost reliance on fossil fuel power plants and result in real-world emissions intensities well above that of conventional hydrogen production. Such rules would also likely promote the deployment of less-flexible electrolyzer technologies that make it more difficult to produce lower-cost hydrogen (absent subsidies) and integrate new variable renewable energy generation.[65]

Partway along the spectrum are designs that the EU and U.S. have adopted to balance the accuracy and administrability of emissions accounting. The "three pillars" framework requires electrolyzers to use new, deliverable, hourly-matched clean electricity, aiming for a tight coupling of clean electricity generation and electrolyzers' hydrogen production in terms of causality, location, and time.[66] Such rules can reduce electrolyzers' chances of inducing climate pollution elsewhere on the power grid. They also support development of more flexible electrolyzer technologies critical for reducing hydrogen production costs and supporting renewable energy integration.[67]

However, even three-pillars schemes do not guarantee a zero-emissions product. For example, if the electrolyzer's new clean electricity resource offsets another entity's obligation to build such resources to meet regulatory carbon cap or renewable generation requirements, then the new clean resource is not "additional," and the resulting hydrogen has a positive emissions impact. So, while three-pillars schemes can help work toward lower-emissions hydrogen production, jurisdictions can take steps to further boost their integrity.

Emissions intensity questions extend beyond electricity procurement—they are further influenced by the scope or lifecycle boundaries of their calculations, such as whether they include indirect or raw materials or hydrogen leakage throughout the value chain. Similar question sets and accounting schemes surround other types of hydrogen production. For example, hydrogen produced from natural gas with CCUS involves nuanced questions around upstream methane leakage and carbon intensity assumptions of methane sources (e.g., waste methane).[68] The specific mechanisms underpinning such frameworks—including phase-in periods and exemptions—are highly complex and differ across jurisdictions to account for their market and policy contexts, but progress is being made toward international alignment.[69]

The emissions accounting framework—and the subsidies that may be tied to it—will affect the quantity and price of hydrogen, the credibility of the "low-emissions" qualifier and actual amount of climate pollution, the technologies deployed to supply it, the demands they place on electricity and gas supply, the operational profile of electrolyzers (i.e., flexible vs. around-the-clock demand), and the markets to which the hydrogen has access (e.g., "low-emissions" hydrogen in one jurisdiction may not count as "low-emissions" in another).[70] Regardless of whether the design principles of emissions accounting schemes ultimately fall within their purview, understanding these nuances can help regulators better assess load forecasts, the operational profiles of new electricity generators and consumers, and potentially the prudence of new regulated hydrogen investments—especially those predicated on exporting hydrogen or hydrogen-derived products to jurisdictions of varying low-emissions hydrogen rules.

**Exploratory questions for regulators:**

- How do policymakers define "low-emissions hydrogen," and what elements of that accounting methodology, tracking, and verification will fall to energy regulators and regulated companies? If regulators play a role in designing rules, how should they balance emissions accuracy with program administrability? What domestic policies (e.g., carbon caps) and importing jurisdictions' emissions accounting rules do they need to consider to design effective, high-integrity rules?
- How do emissions accounting rules for hydrogen influence the demand for and operation of hydrogen electrolyzers, the types and quantities of clean energy resources being built, the evolution of fossil or alternative methane sourcing, and the net impact on climate pollution?
- How might emissions accounting schemes need to evolve as jurisdictions with net zero climate goals have to lower the emissions threshold for what counts as "low-emissions hydrogen" over time?
- Which other agencies and authorities should energy regulators be coordinating with to guide their collective hydrogen decision-making?

## Local air pollution

Hydrogen combustion generally results in NOx emissions—an air pollutant that harms human respiratory systems. All else equal, hydrogen combustion will worsen NOx emissions relative to methane, creating public health issues especially for vulnerable populations if burning it for heat (in buildings or industrial processes) or to generate electricity.

Newer "lean premix" combustion systems can reduce NOx emissions from hydrogen combustion by allowing for lower temperatures. However, they struggle to manage hydrogen's challenging chemical properties, which make it difficult to maintain a steady flame and prevent against flashback risks (wherein the flame travels back into the gas line and can damage equipment). Today's cutting-edge lean premix systems can manage a 50-50 blend by volume of hydrogen and methane, but continued development is needed to achieve systems that can handle 100 percent hydrogen.[71]

Depending on the jurisdiction's environmental regulations, these NOx challenges can complicate hydrogen's use for combustion. For example, indoor air quality goals may preclude hydrogen's use in buildings (e.g., residential or commercial gas stoves), and air quality or technology pollution standards may limit or raise the cost of hydrogen for power generation.

Hydrogen production can also have local air pollution impacts. For example, electrolysis that induces higher fossil fuel power generation elsewhere on the grid would worsen

NOx emissions from those facilities. Methane-based hydrogen production also results in NOx emissions, and adding carbon capture to those facilities would worsen their NOx output, assuming the carbon capture equipment is powered by fossil fuels.

**Exploratory questions for regulators:**

- Does the energy regulator have purview over regulated entities' pollution? If not, how should the energy regulator balance their need to ensure reliable, safe, and cost-effective service for consumers with the emissions reduction mandate of other government agencies?
- How does hydrogen combustion (for heat or power generation) affect local air pollution? Are "hydrogen-ready" power plants set up for low-NOx combustion? Do such plants have appropriate post-combustion emissions control technologies?
- Would local air pollution from hydrogen combustion affect its potential for use as a source of heat or power, given the jurisdiction's public health standards?
- Should regulators anticipate public opposition to siting of facilities that produce or combust hydrogen in vulnerable communities?
- Which other agencies and authorities should energy regulators be coordinating with in order to guide their collective decision-making on hydrogen?

### Water consumption

Hydrogen production draws on water resources in several ways: directly (e.g., water for electrolysis or steam in methane reforming), indirectly (e.g., cooling processes), and upstream (e.g., water treatment, water for cooling power generators, water used across the natural gas value chain). The total water requirement is quite small—meeting the IEA's NZE Scenario hydrogen production forecast would entail less than a quarter of one percent of global freshwater resources.[72] However, the location and context of hydrogen production and use are critical for protecting freshwater availability in water-stressed regions.

In general, the water requirement for hydrogen production is comparable across technologies.[73] The chemical minimum to produce a kilogram of hydrogen is 4.5 liters from steam methane reformation or 9 liters from water electrolysis.[74] When accounting for indirect and upstream requirements, the water demand rises to approximately 20 to 40 liters, with wind-powered electrolysis on the lower end and steam methane reformation with CCUS at the upper end.[75] However, some upstream aspects can amplify water requirements by an order of magnitude, such as the use of nuclear or geothermal power for electrolysis.[76]

In water-stressed regions, hydrogen production may be problematic if it draws on freshwater systems. To mitigate this risk, treated wastewater or desalinated seawater can be part of sufficiently purifying water for hydrogen production (e.g., ultrapure for electrolysis).[77] The extra energy and costs of such processes are marginal (e.g., adding 1 to 4 cents per kilogram of hydrogen to desalinate seawater), but developers will need plans to manage the resulting waste or brine.[78]

Hydrogen production may also exacerbate local water stress if the hydrogen (or hydrogen-derived products like e-fuels) is exported to another region. Hydrogen used within the same region can directly reduce other regional water demands (e.g., from fossil fuel production) and even return water to the local cycle (e.g., when used in a fuel cell), while exports would add to net water consumption. For example, electrolysis powered by renewable electricity consumes less than half the water to produce the same amount of energy as a coal-fired power plant.[79]

**Exploratory questions for regulators:**

- Which water issues does the regulator have authority over (e.g., issuing water rights for groundwater or waste treatment plants, brine disposal for desalination)? Even where water issues fall outside of the regulator's oversight, how do they affect the viability of regulated companies' proposed hydrogen investments?
- Is the proposed hydrogen project in a water-stressed region? Will the hydrogen be used in the same region or exported? If the former, will the hydrogen's use return some water to the atmosphere or displace water consumption in other sectors? Is upstream water consumption in the same or a different region? Would the use of seawater or reclaimed water reduce stress on freshwater systems?
- For electrolyzers drawing on a regulated water distribution company, what rate design is appropriate for this customer class (e.g., declining block pricing will incentivize larger electrolyzer projects, while increasing block pricing will incentivize greater efficiency in water consumption)?
- Which other agencies and authorities should energy regulators be coordinating with in order to guide their collective decision-making on hydrogen?

# CONCLUSION

Governments and energy companies are increasingly looking to hydrogen for its potential to reduce climate pollution and catalyze investment. As a result, energy regulators may soon face hydrogen-related proposals or feel hydrogen's influence on traditional electric and natural gas sectors—and in several jurisdictions, this has begun playing out already. If regulators take nothing else from this paper, it should be this: It is worth developing a proactive approach to regulating hydrogen—including engaging in inter-agency coordination—to arrive at least-regrets decisions.

Regulators can use a holistic understanding of the hydrogen landscape and how it intersects with their jurisdictional context in order to make wise judgments. For example, regulators will need to separate hype from reality in hydrogen demand forecasts—both in terms of where hydrogen will likely be competitive with alternative technologies for decarbonizing specific end uses and in the aggregate—and stay on top of the latest assessments. They will also need to discern where hydrogen production will likely originate, both in terms of technology and location. Such assessments will help regulators better judge which hydrogen-related investments are prudent, how to co-develop the hydrogen, electric, and gas sectors in a manner that avoids putting excess risk or undue cost on consumers, and how to prevent hydrogen from putting people's safety at risk. Regulators will also benefit from understanding how hydrogen-related policy goals, emissions accounting schemes, local air pollution risks, and water needs may impact the industry's development.

With visibility into the issues most likely to affect them, regulators can develop a proactive approach to low-emissions hydrogen that can influence or best manage government policies, energy company proposals, and economic realities. This in turn supports their core mandate of ensuring affordable, reliable, and safe energy services.

# APPENDIX A: RESOURCE LIBRARY

The following offers recommended resources for further reading across the key topics discussed in this paper.

**General information:**

- International Energy Agency, "Global Hydrogen Review 2024," October 2024, https://www.iea.org/reports/global-hydrogen-review-2024
- European Union Agency for the Cooperation of Energy Regulators, "European hydrogen markets: 2024 Market Monitoring Report," November 19, 2024, https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_2024_MMR_Hydrogen_Markets.pdf
- Nathan Johnson, Michael Liebreich, Daniel M. Kammen, Paul Ekins, Russell McKenna, and Iain Staffell, "Realistic roles for hydrogen in the future energy transition," *Nature Reviews Clean Technology*, April 22, 2025, https://www.nature.com/articles/s44359-025-00050-4
- International Energy Agency, "Hydrogen Production Projects Interactive Map," https://www.iea.org/data-and-statistics/data-tools/hydrogen-production-projects-interactive-map

**Interaction with regulated electricity systems:**

- Ann Collier, Dan Esposito, Trevor Gibson, and Lakin Garth, "Insight Brief: Clean Hydrogen for the Electric System," Smart Electric Power Alliance and Energy Innovation, April 2024, https://energyinnovation.org/publication/insight-brief-clean-hydrogen-for-the-electric-system/
- Ghassan Wakim and Kasparas Spokas, "Hydrogen in the Power Sector: Limited Prospects in a Decarbonized Electric Grid," Clean Air Task Force, June 2024, https://www.catf.us/resource/hydrogen-power-sector/
- Eric Gimon, Mark Ahlstrom, and Mike O'Boyle, "Energy Parks: A New Strategy to Meet Rising Electricity Demand," Energy Innovation, December 2024, https://energyinnovation.org/report/energy-parks-a-new-strategy-to-meet-rising-electricity-demand/

**Interaction with regulated natural gas systems:**

- Jan Rosenow, "A meta-review of 54 studies on hydrogen heating," *Cell Reports Sustainability*, December 14, 2023, https://www.sciencedirect.com/science/article/pii/S2949790623000101
- Sara Baldwin, Dan Esposito, and Hadley Tallackson, "Assessing the Viability of Hydrogen Proposals: Considerations for State Utility Regulators and Policymakers," Energy Innovation, March 2022, https://energyinnovation.org/publication/assessing-the-viability-of-hydrogen-proposals-considerations-for-state-utility-regulators-and-policymakers/
- Massachusetts Department of Public Utilities, "Order 20-80-B," December 6, 2023, https://www.mass.gov/news/department-of-public-utilities-issues-order-20-80
- Robin Gaster, "A Realist Approach to Hydrogen," Information Technology & Innovation Foundation, January 16, 2024, https://itif.org/publications/2024/01/16/a-realist-approach-to-hydrogen/
- Mark LeBel, Ronny Sandoval, Natalie Mims Frick, Jeffrey Deason, "Opportunities for Integrating Electric and Gas Planning," Regulatory Assistance Project and Berkeley Lab, January 2025, https://eta-publications.lbl.gov/sites/default/files/2025-01/opportunity_integrate_electric_gas_planning_20241223_final_2025jan06.pdf

**Regulatory oversight of hydrogen infrastructure:**

- European Union Agency for the Cooperation of Energy Regulators and Council of European Energy Regulators, "When and How to Regulate Hydrogen Networks?" February 9, 2021, https://www.acer.europa.eu/sites/default/files/documents/Official_documents/Position_Papers/Position%20papers/ACER_CEER_WhitePaper_on_the_regulation_of_hydrogen_networks_2020-02-09_FINAL.pdf
- European Union, "Directive (EU) 2024/1788 of the European Parliament and of the Council of 13 June 2024 on common rules for the internal markets for renewable gas, natural gas and hydrogen, amending Directive (EU) 2023/1791 and repealing Directive 2009/73/EC (recast) (Text with EEA relevance)," July 15, 2024, https://eur-lex.europa.eu/eli/dir/2024/1788/oj/eng
- British Columbia Utilities Commission, "Inquiry into the Regulation of Hydrogen Energy Services," November 23, 2023, https://docs.bcuc.com/documents/other/2023/doc_75049_bcuc-inquiry-hydrogen-regulation-finalreport.pdf
- Andreas Jahn, "Getting the hydrogen network we need for decarbonisation," Regulatory Assistance Project, November 3, 2022, https://www.raponline.org/knowledge-center/getting-the-hydrogen-network-we-need-for-decarbonisation/

**Pipeline and appliance safety:**

- Hydrogen Tools, "Best Practices," https://h2tools.org/bestpractices/best-practices-overview
- Richard B. Kuprewicz, "Safety of Hydrogen Transportation by Gas Pipelines," Accufacts Inc., November 28, 2022, https://pstrust.org/wp-content/uploads/2022/11/11-28-22-Final-Accufacts-Hydrogen-Pipeline-Report.pdf
- International Renewable Energy Agency, "A quality infrastructure roadmap for green hydrogen," 2024, https://www.irena.org/Publications/2024/Nov/A-Quality-Infrastructure-Roadmap-for-green-hydrogen

**Government policy goals:**

- Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions," Energy Innovation, August 27, 2024, https://energyinnovation.org/report/hydrogen-policys-narrow-path-delusions-and-solutions/
- Matthias Deutsch et al., "Prioritising hydrogen for the most effective uses – an overview," Agora Industry, International Council on Clean Transportation, and Regulatory Assistance Project, March 25, 2025, https://www.agora-industry.org/publications/prioritising-hydrogen-for-the-most-effective-uses
- International Renewable Energy Agency, "Green hydrogen strategy: A guide to design," 2024, https://www.irena.org/Publications/2024/Jul/Green-hydrogen-strategy-A-guide-to-design

**Emissions accounting schemes:**

- Dan Esposito, Eric Gimon, and Mike O'Boyle, "Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions And Grow the Industry," Energy Innovation, April 12, 2023, https://energyinnovation.org/report/smart-design-of-45v-hydrogen-production-tax-credit-will-reduce-emissions-and-grow-the-industry/
- International Renewable Energy Agency, "Global trade in green hydrogen derivatives: Trends in regulations, standardisation, and certification," 2024, https://www.irena.org/Publications/2024/Oct/Global-trade-in-green-hydrogen-derivatives-Trends-in-regulation-standardisation-and-certification

**Local air pollution:**

- Air Quality Expert Group, "Air pollution arising from hydrogen combustion," 2023, https://uk-air.defra.gov.uk/assets/documents/reports/cat05/2411071337_H2_combustion_note_proof.pdf
- Clean Energy Group, "Hydrogen Areas of Concern – NOx Emissions," https://www.cleanegroup.org/initiatives/hydrogen/areas-of-concern/

**Water consumption:**

- Kaitlyn Ramirez, Tessa Weiss, Thomas Kirk, and Chathurika Gamage, "Hydrogen Reality Check: Distilling Green Hydrogen's Water Consumption," RMI, August 2, 2023, https://rmi.org/hydrogen-reality-check-distilling-green-hydrogens-water-consumption/

# APPENDIX B: HYDROGEN BACKGROUND

A large but narrowly-focused hydrogen industry exists today, with 97 MMT produced globally in 2023.[80] This production derives almost exclusively from fossil fuels and emits 920 MMT of $CO_2$ per year (nearly 2 percent of global GHG emissions).[81] Almost all of this hydrogen is used to refine oil, make chemicals (mostly ammonia and methanol), or purify iron ore for steelmaking. Hydrogen production and use generally takes place either at industrial sites paired with large co-located users, or within dense industrial clusters with purpose-built hydrogen pipelines.

Hydrogen is of growing interest for the energy transition because—at least in theory—it *can* be produced without emitting greenhouse gases and it *can* be used to provide many of the same services as fossil fuels across all economic sectors. While low-emissions hydrogen may not be able to compete with alternative clean technologies in most arenas, it holds potential to decarbonize applications that are hard or impossible to electrify. Thus, its near-term development is important to decarbonizing global energy systems by 2050. This potential, paired with energy security and economic value, has led to policies intended to clean up and expand the industry.

However, hydrogen is not necessarily a low-emissions or cost-effective solution, and its production and use bring a new suite of challenges. If hydrogen policies and regulations are not designed with care, they could delay, reverse, or raise the cost of emission reductions and endanger public health and safety.[82] Even in jurisdictions where energy regulators have little or no control over the emissions intensity of hydrogen production or a government's hydrogen goals, it is important to understand hydrogen's value proposition and how it can support or hinder progress toward climate goals, as this supports prudent action on those issues that do fall in their purview.

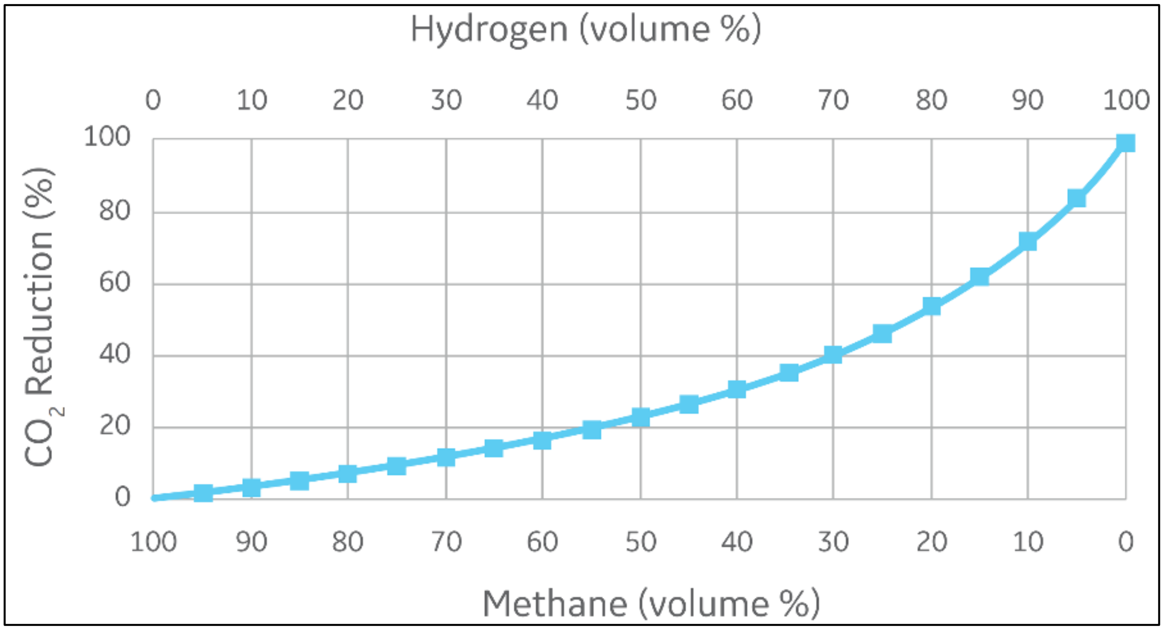
Ultimately, hydrogen is a means to an end in decarbonization, not an end in itself (at least, beyond its existing uses). To the degree hydrogen is pursued strictly for economic reasons, it is unlikely to deliver on its promise. New demand for hydrogen will only materialize if buyers trust that the hydrogen will reduce emissions relative to the status quo. Further, if hydrogen subsidies drive its use in sectors where other clean technologies would outcompete it on a level playing field, that demand may quickly dry up as well. Even if regulators lack control over hydrogen policy, understanding these dynamics can help make decisions that keep costs low (such as by minimizing spending on would-be stranded assets) while supporting the type of hydrogen growth that can meet jurisdictions' climate and economic development goals.

### Hydrogen properties

Hydrogen is a tricky molecule to manage. As the smallest molecule in the universe, it is especially prone to leakage, which can threaten public safety, project economics, and climate. Hydrogen gas is colorless and odorless, and unlike natural gas (methane), it does not pair with an odorant that would allow for detecting leaks via smell. Relative to natural gas, hydrogen ignites far more easily (with a barely perceptible flame), has a higher flame temperature (which can drive higher NOx emissions from combustion), and has a faster flame speed (which can travel back through gas lines and damage equipment).[83] In general, hydrogen's physical challenges can be managed, but it is generally easier to do so in open-air industrial settings with trained personnel, robust safety standards, monitoring equipment, and infrastructure built specifically to manage hydrogen.

Hydrogen's properties also have economic and climate impacts related to its transport and use. It requires much lower temperatures and higher energy use than natural gas to liquify and transport via truck or maritime vessel. It has a global warming impact approximately 37 times higher than $CO_2$ over a 20-year timespan, meaning leaks throughout its value chain can diminish its climate benefits.[84] And it has a volumetric energy density of about a third of methane, meaning that blending hydrogen and methane will deliver lower-than-expected GHG emissions reductions and energy content. For example, a 20 percent blend of hydrogen with methane will only reduce emissions by approximately 7 percent (assuming zero-emissions hydrogen), and it will deliver less heat than 100 percent methane, all else equal, with implications for power plant output.[85]

***Figure 7. Relationship between CO2 emissions and hydrogen/methane***




*Source: GE Vernova.*[86]

## Hydrogen production

While hydrogen contains no carbon and does not emit $CO_2$ when consumed, the conventional hydrogen production process is highly polluting. Nearly all hydrogen today is made from natural gas or gasified coal in the steam methane reformation process, in which steam is used to split hydrogen from the methane ($CH_4$) molecule (often termed "gray" hydrogen). This process emits approximately 10 to 26 $kgCO_2e/kgH_2$.[87] By comparison, using this hydrogen to displace natural gas in power generation would only offset 7 $kgCO_2e/kgH_2$.[88]

"Low-emissions" hydrogen generally refers to reducing the emissions intensity of hydrogen production to below a certain point (e.g., 4 $kgCO_2e/kgH_2$ in the U.S.)—though this value varies by jurisdiction and regulation. Even then, jurisdictions targeting net zero economies will likely need to lower these thresholds over time.[89] In general, low-emissions hydrogen policy support (including access to lucrative subsidies and expansive export markets) requires adhering to specific project designs and emissions accounting rules. While there are many paths to reducing hydrogen production's emissions intensity, they generally fall in three camps:

1. **Using clean electricity to split hydrogen from water ($H_2O$) via electrolysis (often called "green" or "renewable" hydrogen).** Electrolysis offers a pathway to make zero-carbon hydrogen at prices lower than today's fossil-based hydrogen while supporting the integration of variable renewable energy on the power grid. However, the emissions intensity of electrolytic hydrogen depends on the source of electricity—electrolyzers that increase reliance on natural gas- or coal-fired power result in hydrogen with emissions intensities far higher than steam methane reformation (15 to 50 $kgCO_2e/kgH_2$).[90] Upstream emissions accounting for electrolytic hydrogen is extremely technical and requires consideration of marginal grid impacts, offset schemes, and reporting requirements. In the U.S. and EU, this has led to "three pillars" schemes that require electrolyzers to use new, deliverable, hourly-matched clean electricity to count as zero-carbon or renewable hydrogen.[91]
2. **Capturing some or all of the carbon from processes that produce hydrogen from fossil fuels or biomass (often called "blue" hydrogen).** This may include conventional steam methane reformation with CCUS, autothermal reforming with CCUS (which can achieve higher $CO_2$ capture rates), or pyrolysis (which produces solid carbon and may be termed "turquoise" hydrogen).[92] Core challenges include upstream methane leakage, carbon capture performance issues (e.g., achieving much lower capture rates than promised), and long-term dependence on policy support (e.g., tax credits, carbon pricing) due to adding CCUS equipment and operational costs to the hydrogen production process.
3. **Drilling for "geologic" or "natural" hydrogen in underground deposits.** This could be a boon if deposits are discovered in economically viable quantities and locations, but hydrogen deposit discovery is still highly uncertain today.

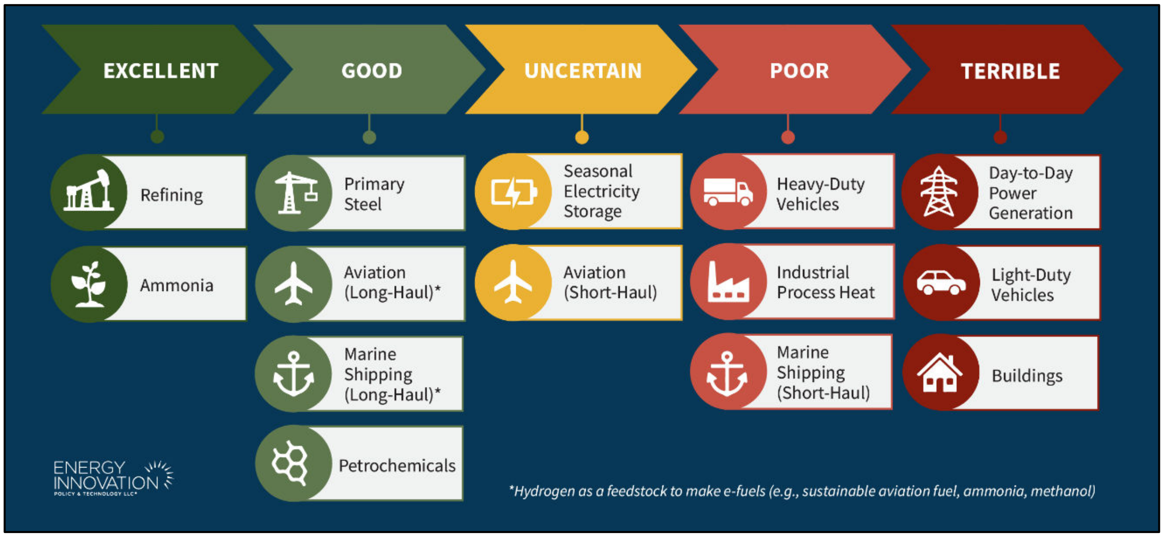
## Hydrogen use

Hydrogen can be used as a chemical feedstock to make or alter other compounds, to produce heat from combustion, or to generate electricity from fuel cells. Hydrogen's chemical feedstock uses include refining, making chemicals, purifying iron ore for steelmaking, and producing e-fuels for long-haul marine shipping and aviation. These products all face little competition from alternative low-carbon technologies and are likely to require at least some low-emissions hydrogen in a clean economy. At minimum, an enormous global market (97 MMT in 2023) exists for cleaning up existing uses of dirty hydrogen, and this should be a top priority for the use of low-emissions hydrogen.[93]

By contrast, hydrogen's energy uses—whether via combustion to produce heat or fuel cells to generate electricity—may struggle to compete with more efficient electric alternatives (for buildings, ground transportation, and at least low- and medium-temperature industrial heat) or more efficient clean energy and energy storage resources (for power generation). One potential exception is hydrogen used for seasonal to multi-annual energy storage, as it is possible to store very large volumes of hydrogen underground for re-conversion to electricity during periods of low renewable energy output. Hydrogen may also be situationally more competitive for certain high-temperature industrial process heat applications.

In sum, a large low-emissions hydrogen economy will be important for decarbonizing the feedstock-based applications, but its extension to energy-based applications often risks raising consumer costs due to bypassing or replacing more efficient, lower cost technologies.

***Figure 8. Electrolytic hydrogen's competitive prospects for decarbonization***




*This graphic presents the results of a broad assessment of where electrolytic hydrogen is likely or unlikely to be competitive with alternative decarbonization technologies like electrification* *and biofuels. Even "terrible" applications may see rare exceptions in some jurisdictions or circumstances, but as a general rule, hydrogen will not be a financially viable option. In some cases, the ranking represents a weighted average—for example, for industrial process heat, electrolytic hydrogen may have viable applications in high-temperature applications but fewer competitive opportunities for serving low- and medium-temperature needs. See Energy Innovation's "Hydrogen Policy's Narrow Path: Delusions & Solutions" paper for more detail.*[94]

# REFERENCES


[1] "Green Hydrogen Strategy: A Guide to Design" (International Renewable Energy Agency, 2024), 13, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2024/Jul/IRENA_Green_hydrogen_strategy_design_2024.pdf.
[2] "Net Zero by 2050: A Roadmap for the Global Energy Sector" (International Energy Agency, October 2021), tbl. 2.7, https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf; "World Energy Outlook 2024" (International Energy Agency, October 2024), tbl. A.28, https://iea.blob.core.windows.net/assets/140a0470-5b90-4922-a0e9-838b3ac6918c/WorldEnergyOutlook2024.pdf; Matthias Deutsch, "Prioritising Hydrogen for the Most Effective Uses – an Overview," Agora Industry, International Council on Clean Transportation, and Regulatory Assistance Project, March 25, 2025, 9, https://www.agora-industry.org/publications/prioritising-hydrogen-for-the-most-effective-uses.
[3] Jan Rosenow, "A Meta-Review of 54 Studies on Hydrogen Heating," Cell Reports Sustainability, January 26, 2024, https://www.sciencedirect.com/science/article/pii/S2949790623000101; Nathan Johnson et al., "Realistic Roles for Hydrogen in the Future Energy Transition" (Nature Reviews Clean Technology, April 22, 2025), fig. 2, https://www.nature.com/articles/s44359-025-00050-4; Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions" (Energy Innovation, August 27, 2024), fig. 3, https://energyinnovation.org/report/hydrogen-policys-narrow-path-delusions-and-solutions/.
[4] "When and How to Regulate Hydrogen Networks?" (European Union Agency for the Cooperation of Energy Regulators, Council of European Energy Regulators, February 9, 2021), 3, https://www.acer.europa.eu/sites/default/files/documents/Official_documents/Position_Papers/Position%20papers/ACER_CEER_WhitePaper_on_the_regulation_of_hydrogen_networks_2020-02-09_FINAL.pdf; "European Hydrogen Markets: 2024 Market Monitoring Report" (European Union Agency for the Cooperation of Energy Regulators, November 19, 2024), https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_2024_MMR_Hydrogen_Markets.pdf.
[5] Kaitlyn Ramirez et al., "Hydrogen Reality Check: Distilling Green Hydrogen's Water Consumption," RMI, August 2, 2023, https://rmi.org/hydrogen-reality-check-distilling-green-hydrogens-water-consumption/.
[6] "World Energy Outlook 2024," tbl. A.28.
[7] "World Energy Outlook 2024," 163; "World Energy Outlook 2024," tbl. A.3b, A.3c, A.28, 3.2.
[8] "Net Zero by 2050: A Roadmap for the Global Energy Sector," tbl. 2.7; "World Energy Outlook 2024," tbl. A.28; Matthias Deutsch, "Prioritising Hydrogen for the Most Effective Uses – an Overview," 9.
[9] "Green Hydrogen Strategy: A Guide to Design," 13.
[10] "Green Hydrogen Strategy: A Guide to Design," fig. 3.
[11] "Global Hydrogen Review 2024" (International Energy Agency, October 2024), 21–22, https://iea.blob.core.windows.net/assets/89c1e382-dc59-46ca-aa47-9f7d41531ab5/GlobalHydrogenReview2024.pdf.
[12] "Global Hydrogen Review 2024," fig. 7.1.
[13] Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions"; Nathan Johnson et al., "Realistic Roles for Hydrogen in the Future Energy Transition."
[14] Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions," fig. 1.
[15] "World Energy Outlook 2024," 124; "Electricity Consumption," International Energy Agency, accessed March 31, 2025, https://www.iea.org/reports/electricity-information-overview/electricity-consumption.
[16] "Global Hydrogen Review 2024," 54; Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions," 17, 25.
[17] Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions," 25.
[18] Michelle Solomon and Sara Baldwin, "Grid Reliability in the Clean Energy Transition: A Primer for Policymakers" (Energy Innovation, February 2025), 36, https://energyinnovation.org/report/grid-reliability-in-the-clean-energy-transition/.
[19] Ghassan Wakim and Kasparas Spokas, "Hydrogen in the Power Sector: Limited Prospects in a Decarbonized Electric Grid," Clean Air Task Force, June 2024, 11, https://www.catf.us/resource/hydrogen-power-sector/; Ann Collier et al., "Insight Brief: Clean Hydrogen for the Electric System" (Energy Innovation, Smart Electric Power Alliance, April 2024), 9, https://energyinnovation.org/report/insight-brief-clean-hydrogen-for-the-electric-system/.
[20] Ann Collier et al., "Insight Brief," 9.

[21] Ghassan Wakim and Kasparas Spokas, "Hydrogen in the Power Sector: Limited Prospects in a Decarbonized Electric Grid," fig. 4.
[22] Eric Gimon, "How Feasible Is Green Hydrogen? Some Back-of-the-Envelope Calculations," *Energy Systems Integration Group* (blog), March 27, 2024, https://www.esig.energy/how-feasible-is-green-hydrogen-some-back-of-the-envelope-calculations/.
[23] "EU Hydrogen Strategy under the EU Green Deal," European Hydrogen Observatory, September 11, 2023, https://observatory.clean-hydrogen.europa.eu/eu-policy/eu-hydrogen-strategy-under-eu-green-deal.
[24] "European Electricity Review 2024," *Ember* (blog), accessed April 23, 2025, https://ember-energy.org/latest-insights/european-electricity-review-2024.
[25] Marie Espitalier-Noël et al., "Clean Hydrogen Monitor 2024" (Hydrogen Europe, 2024), 7, https://hydrogeneurope.eu/wp-content/uploads/2023/10/Clean_Hydrogen_Monitor_11-2023_DIGITAL.pdf.
[26] Emma Nguyen et al., "Impacts of Intermittency on Low-Temperature Electrolysis Technologies: A Comprehensive Review," *International Journal of Hydrogen Energy* 70 (June 12, 2024): 476, 481, https://doi.org/10.1016/j.ijhydene.2024.05.217.
[27] "World Energy Outlook 2024," tbl. 3.2.
[28] "World Energy Outlook 2024," tbl. 3.2.
[29] "World Energy Outlook 2024," tbl. 3.2.
[30] "Global Hydrogen Review 2024," 123; Tom DiChristopher, "Gas Utilities Increasingly Focus on Pipeline Blending in Hydrogen Pilot Projects," S&P Global Market Intelligence, May 17, 2023, https://www.spglobal.com/market-intelligence/en/news-insights/articles/2023/5/gas-utilities-increasingly-focus-on-pipeline-blending-in-hydrogen-pilot-projects-75656565.
[31] Jan Rosenow, "A Meta-Review of 54 Studies on Hydrogen Heating"; Nathan Johnson et al., "Realistic Roles for Hydrogen in the Future Energy Transition"; Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions."
[32] Sara Baldwin, Dan Esposito, and Hadley Tallackson, "Assessing The Viability Of Hydrogen Proposals: Considerations For State Utility Regulators And Policymakers" (Energy Innovation, March 29, 2022), https://energyinnovation.org/report/assessing-the-viability-of-hydrogen-proposals-considerations-for-state-utility-regulators-and-policymakers/; Richard Lowes, "Regret-Ready: A Briefing on United Kingdom Proposals for the Mandating of 'Hydrogen-Ready' Gas Boilers," Regulatory Assistance Project, March 1, 2023, https://www.raponline.org/knowledge-center/regret-ready-briefing-on-united-kingdom-proposals-for-mandating-hydrogen-ready-gas-boilers/.
[33] "Global Hydrogen Review 2024," 78–79.
[34] "European Hydrogen Markets: 2024 Market Monitoring Report," 7.
[35] "Department of Public Utilities Issues Order 20-80," Massachusetts Department of Public Utilities, December 6, 2023, https://www.mass.gov/news/department-of-public-utilities-issues-order-20-80.
[36] "Commission Decision Granting Application With Modifications, Requiring Filings, And Issuing Certain Directives To Guide Next Clean Heat Plan Filing," Colorado Department of Regulatory Agencies, June 10, 2024, 82, https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_dec=30982&p_session_id=.
[37] Jovi Ho, "City Energy Harbours Hydrogen Dreams to Help Homes Decarbonise," The Edge Singapore, March 21, 2022, https://www.pressreader.com/singapore/the-edge-singapore/20220321/281767042715077; "50 Years of Locally Produced Energy at Oʻahu's SNG Plant," *Hawaii Business Magazine* (blog), December 16, 2024, https://www.hawaiibusiness.com/hawaii-has-synthetic-natural-gas-plant-50-year-anniversary/; "Hydrogen," Towngas Smart Energy, accessed April 24, 2025, https://www.towngassmartenergy.com/zh-hant/document/hydrogen/; "Gas Production," Towngas, accessed April 24, 2025, https://app-tg-prd-tgportal-eas-01.azurewebsites.net/en/About-Us/Hong-Kong-Utility-Business/Gas-Production.
[38] "When and How to Regulate Hydrogen Networks?," 2.
[39] Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions," 40–41, 51–52.
[40] "DIRECTIVE (EU) 2024/1788 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 June 2024 on Common Rules for the Internal Markets for Renewable Gas, Natural Gas and Hydrogen, Amending Directive (EU) 2023/1791 and Repealing Directive 2009/73/EC," EUR-Lex, July 15, 2024, https://eur-lex.europa.eu/eli/dir/2024/1788/oj/eng.
[41] "Inquiry into the Regulation of Hydrogen Energy Services" (British Columbia Utilities Commission, November 23, 2023), https://docs.bcuc.com/documents/other/2023/doc_75049_bcuc-inquiry-hydrogen-regulation-finalreport.pdf.
[42] "DIRECTIVE (EU) 2024/1788 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 June 2024 on Common Rules for the Internal Markets for Renewable Gas, Natural Gas and Hydrogen, Amending Directive (EU) 2023/1791 and Repealing Directive 2009/73/EC," art. 46.

[43] "DIRECTIVE (EU) 2024/1788 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 June 2024 on Common Rules for the Internal Markets for Renewable Gas, Natural Gas and Hydrogen, Amending Directive (EU) 2023/1791 and Repealing Directive 2009/73/EC," art. 78.
[44] "When and How to Regulate Hydrogen Networks?," 3; "European Hydrogen Markets: 2024 Market Monitoring Report."
[45] Richard B. Kuprewicz, "Safety of Hydrogen Transportation by Gas Pipelines" (Accufacts, November 28, 2022), 4–6, https://pstrust.org/wp-content/uploads/2022/11/11-28-22-Final-Accufacts-Hydrogen-Pipeline-Report.pdf.
[46] Aliaksei Patonia and Rahmatallah Poudineh, "Global Trade of Hydrogen: What Is the Best Way to Transfer Hydrogen over Long Distances?" (Oxford Institute for Energy Studies, September 2022), 14–15, https://www.oxfordenergy.org/publications/global-trade-of-hydrogen-what-is-the-best-way-to-transfer-hydrogen-over-long-distances/.
[47] Richard B. Kuprewicz, "Safety of Hydrogen Transportation by Gas Pipelines," 2.
[48] "Mapping Safe Hydrogen Standards," *Safe Hydrogen Project | CGA* (blog), October 31, 2012, https://safehydrogenproject.org/mapping-safe-hydrogen/.
[49] "When and How to Regulate Hydrogen Networks?," 7.
[50] Renee McVay, "Methane Emissions from U.S. Gas Pipeline Leaks" (Environmental Defense Fund, August 2023), 3, https://www.edf.org/sites/default/files/documents/Pipeline%20Methane%20Leaks%20Report.pdf.
[51] "Hydrogen," IEA, accessed March 31, 2025, https://www.iea.org/energy-system/low-emission-fuels/hydrogen; "Global Gas Infrastructure Tracker," *Global Energy Monitor* (blog), October 17, 2024, https://globalenergymonitor.org/projects/global-gas-infrastructure-tracker/.
[52] "Hydrogen Pipelines Are Making Progress around the World. These Countries Are Leading the Way," World Economic Forum, December 13, 2023, https://www.weforum.org/stories/2023/12/hydrogen-pipelines-countries-fastest/.
[53] Rana Al Homoud et al., "Critical Geochemical and Microbial Reactions in Underground Hydrogen Storage: Quantifying Hydrogen Loss and Evaluating CO2 as Cushion Gas," *Hydrogen* 6, no. 1 (March 2025): 4, https://doi.org/10.3390/hydrogen6010004.
[54] Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions," 15–16; Richard B. Kuprewicz, "Safety of Hydrogen Transportation by Gas Pipelines."
[55] Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions," 15.
[56] "2022 Long-Term Gas Resource Plan" (FortisBC Energy Inc., May 2022), ES-13, https://docs.bcuc.com/documents/proceedings/2022/doc_66503_b-1-fei-2022-longtermgasresourceplan.pdf; "2022 Long-Term Gas Resource Plan," sec. 7.4.1; "Enabling Higher-Hydrogen Blending in the Natural Gas Distribution System: Global Technology and Market Scan Summary Report for Distributing Hydrogen at >5% into Natural Gas Energy Distribution Systems" (Canadian Gas Association, October 2022), 11, https://www.cga.ca/wp-content/uploads/2022/10/CGA-Hydrogen-Blending-Greater-than-5.pdf.
[57] "Hydrogen," European Commission, accessed March 31, 2025, https://energy.ec.europa.eu/topics/eus-energy-system/hydrogen_en; "National Hydrogen Strategy 2024" (Australian Government - Department of Climate Change, Energy, the Environment and Water, 2024), 91, https://www.dcceew.gov.au/sites/default/files/documents/national-hydrogen-strategy-2024.pdf; "Global Hydrogen Review 2023" (International Energy Agency, December 2023), 148–49, https://iea.blob.core.windows.net/assets/ecdfc3bb-d212-4a4c-9ff7-6ce5b1e19cef/GlobalHydrogenReview2023.pdf; "National Hydrogen Strategy – Policies," International Energy Agency, May 25, 2023, https://www.iea.org/policies/16971-national-hydrogen-strategy.
[58] "ACER's Hydrogen Monitoring Report Foresees That Europe Is Likely to Miss Its 2030 Renewable Hydrogen Targets," European Union Agency for the Cooperation of Energy Regulators, November 19, 2024, https://acer.europa.eu/news/acers-hydrogen-monitoring-report-foresees-europe-likely-miss-its-2030-renewable-hydrogen.
[59] Adil Faouzi, "Morocco's Potential as Europe's Hydrogen Supplier Faces Challenges," *Morocco World News* (blog), February 20, 2024, https://www.moroccoworldnews.com/2024/02/22983/moroccos-potential-as-europes-hydrogen-supplier-faces-challenges/.
[60] "Global Hydrogen Review 2024," 173–74.
[61] Dan Esposito, "Clean Hydrogen Rules Can Catalyze Growth — If Industry Unites behind Them," Latitude Media, January 15, 2025, https://www.latitudemedia.com/news/clean-hydrogen-rules-can-catalyze-growth-if-industry-unites-behind-them/.
[62] "Global Hydrogen Review 2024," fig. 7.1.

[63] Michaela Holl et al., “Low-Carbon Hydrogen in the EU: Towards a Robust EU Definition in View of Costs, Trade and Climate Protection” (Agora Energiewende and Agora Industry, 2024), 5, https://www.agora-energiewende.org/fileadmin/Projekte/2024/2024-11_EU_Low_Carbon_H2/A-EW_334_Low_Carbon_H2_WEB.pdf.
[64] “Global Hydrogen Review 2024,” 210; Dan Esposito, Eric Gimon, and Mike O’Boyle, “Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow the Industry” (Energy Innovation, April 2023), fig. A2, https://energyinnovation.org/report/smart-design-of-45v-hydrogen-production-tax-credit-will-reduce-emissions-and-grow-the-industry/.
[65] Dan Esposito, “Evidence Shows Three Pillars Remain Crucial for 45V Hydrogen Tax Credit to Protect Climate, Consumers, Industry,” *Energy Innovation* (blog), July 25, 2024, 2–3, https://energyinnovation.org/report/evidence-shows-three-pillars-remain-crucial-for-45v-hydrogen-tax-credit-to-protect-climate-consumers-industry/.
[66] “Global Hydrogen Review 2024,” 196; “U.S. Department of the Treasury Releases Final Rules for Clean Hydrogen Production Tax Credit,” U.S. Department of the Treasury, February 8, 2025, https://home.treasury.gov/news/press-releases/jy2768.
[67] Dan Esposito, Eric Gimon, and Mike O’Boyle, “Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow the Industry,” 14–16.
[68] Danny Cullenward, Emily Grubert, and Wilson Ricks, “Methane Offsets in the Final Hydrogen Production Tax Credit Regulations,” *Kleinman Center for Energy Policy* (blog), January 6, 2025, https://kleinmanenergy.upenn.edu/commentary/blog/methane-offsets-in-the-final-hydrogen-production-tax-credit-regulations/.
[69] “Global Hydrogen Review 2024,” 194–99.
[70] Dan Esposito, Eric Gimon, and Mike O’Boyle, “Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow the Industry,” 14–16.
[71] Jeffrey Goldmeer, “Solving the Challenge of Lean Hydrogen Premix Combustion with Highly Reactive Fuels,” *Turbomachinery Magazine*, November/December 2020, December 21, 2020, https://www.turbomachinerymag.com/view/solving-the-challenge-of-lean-hydrogen-premix-combustion-with-highly-reactive-fuels.
[72] Kaitlyn Ramirez et al., “Hydrogen Reality Check: Distilling Green Hydrogen’s Water Consumption.”
[73] “Can Water Usage for Electrolysis Pose Problems for Parts of the United States Currently Facing Water Shortages?,” U.S. Department of Energy, accessed March 31, 2025, https://www.energy.gov/eere/fuelcells/can-water-usage-electrolysis-pose-problems-parts-united-states-currently-facing.
[74] Rain Saulnier, Keith Minnich, and P. Kim Sturgess, “Water for the Hydrogen Economy” (WaterSMART Solutions Ltd., November 2020), 3–4, https://watersmartsolutions.ca/wp-content/uploads/2020/12/Water-for-the-Hydrogen-Economy_WaterSMART-Whitepaper_November-2020.pdf.
[75] Kaitlyn Ramirez et al., “Hydrogen Reality Check: Distilling Green Hydrogen’s Water Consumption,” fig. 1; “Development of a Life Cycle Inventory of Water Consumption Associated with the Production of Transportation Fuels” (Argonne National Laboratory, October 2015), tbl. 22, https://publications.anl.gov/anlpubs/2015/10/121551.pdf; Andi Mehmeti et al., “Life Cycle Assessment and Water Footprint of Hydrogen Production Methods: From Conventional to Emerging Technologies,” *Environments* 5, no. 2 (February 2018): tbl. 1, https://doi.org/10.3390/environments5020024; McKenzie Hubert et al., “Hydrogen Shot: Water Electrolysis Technology Assessment” (U.S. Department of Energy, December 2024), 19–20, https://www.energy.gov/sites/default/files/2024-12/hydrogen-shot-water-electrolysis-technology-assessment.pdf.
[76] Elizabeth Connelly et al., “Resource Assessment for Hydrogen Production” (National Renewable Energy Laboratory, July 2020), fig. 23, https://www.nrel.gov/docs/fy20osti/77198.pdf; McKenzie Hubert et al., “Hydrogen Shot: Water Electrolysis Technology Assessment,” 20.
[77] Piotr Zawadzki, Beata Kończak, and Adam Smoliński, “Municipal Wastewater Reclamation: Reclaimed Water for Hydrogen Production by Electrolysis – A Case Study,” *Measurement* 216 (July 1, 2023): 112928, https://doi.org/10.1016/j.measurement.2023.112928; Henrik Tækker Madsen, “Water Treatment for Green Hydrogen: What You Need to Know,” *Hydrogen Tech World* (blog), October 27, 2022, https://hydrogentechworld.com/water-treatment-for-green-hydrogen-what-you-need-to-know.
[78] “Can Water Usage for Electrolysis Pose Problems for Parts of the United States Currently Facing Water Shortages?”
[79] Kaitlyn Ramirez et al., “Hydrogen Reality Check: Distilling Green Hydrogen’s Water Consumption.”
[80] “Global Hydrogen Review 2024,” 9.
[81] “Global Hydrogen Review 2024,” 22.

[82] Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions," 4.
[83] Richard B. Kuprewicz, "Safety of Hydrogen Transportation by Gas Pipelines," 4–6.
[84] Maria Sand et al., "A Multi-Model Assessment of the Global Warming Potential of Hydrogen," *Communications Earth & Environment* 4, no. 1 (June 7, 2023): 1–12, https://doi.org/10.1038/s43247-023-00857-8.
[85] Sara Baldwin, Dan Esposito, and Hadley Tallackson, "Assessing The Viability Of Hydrogen Proposals," 8.
[86] "Hydrogen for Power Generation: Experience, Requirements, and Implications for Use in Gas Turbines" (GE, 2022), fig. 5, https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf.
[87] "Global Hydrogen Review 2024," 208–9.
[88] Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions," fig. 4.
[89] Michaela Holl et al., "Low-Carbon Hydrogen in the EU: Towards a Robust EU Definition in View of Costs, Trade and Climate Protection," 5.
[90] Dan Esposito, Eric Gimon, and Mike O'Boyle, "Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow the Industry," fig. ES-1.
[91] "Global Hydrogen Review 2024," 196; "U.S. Department of the Treasury Releases Final Rules for Clean Hydrogen Production Tax Credit."
[92] "Global Hydrogen Review 2024," 152.
[93] "Global Hydrogen Review 2024," fig. 2.1.
[94] Dan Esposito, "Hydrogen Policy's Narrow Path: Delusions & Solutions," fig. 1.