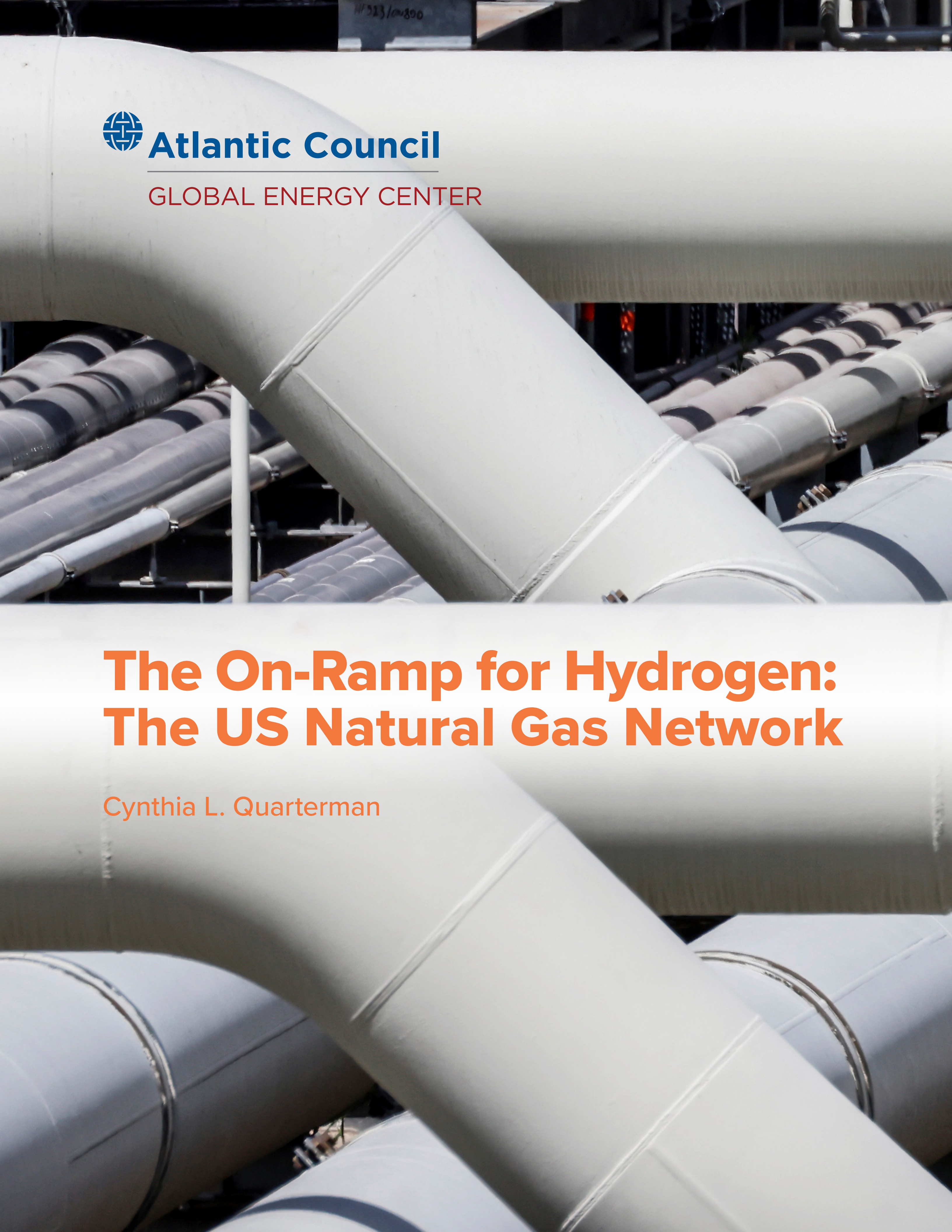

Atlantic Council

GLOBAL ENERGY CENTER

The On-Ramp for Hydrogen: The US Natural Gas Network

Cynthia L. Quarterman

The Atlantic Council Global Energy Center develops and promotes pragmatic and nonpartisan policy solutions designed to advance global energy security, enhance economic opportunity, and accelerate pathways to net-zero emissions.

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Cover photo: Natural gas infrastructure, including pipelines and compressors, can accommodate a blend of hydrogen and natural gas. REUTERS/Hannibal Hanschke.

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Executive Summary

The use of hydrogen as an energy resource has become the latest salvo in the United States' fight against climate change. When used as a fuel, hydrogen releases no climate-warming emissions, making its promise rich for decarbonizing certain applications—and policymakers have acted to encourage growth in the nascent industry by providing incentives and funding through the 2022 Inflation Reduction Act (IRA) and the 2021 Bipartisan Infrastructure Law.

To expedite hydrogen availability across the country, particularly as a chemical feedstock or transportation fuel, infrastructure must be in place to move it from production sites to end users. In the United States, approximately 1,600 miles of pipeline are dedicated to hydrogen, but they are primarily concentrated in the Gulf Coast, where hydrogen serves as a feedstock to industrial users. Building new hydrogen-dedicated pipelines is costly and time consuming, so to quickly increase the use of hydrogen in other US regions, some operators have started blending hydrogen into existing natural gas pipeline infrastructure, and stakeholders are looking to expand on this approach further.

Converting natural gas pipelines for hydrogen service, however, is hardly without challenges. In considering conversion, stakeholders must gain a better understanding of, among other things, two significant issues: First, the high-strength steel of which some US pipelines are made may be especially vulnerable to hydrogen embrittlement, which can lead to leakage and an increased risk of ignition; and, second, while it emits zero carbon, hydrogen is less energy efficient when blended into the natural gas network due to the increased energy required to move it through pipelines compared with natural gas alone.

For now, however, the perfect should not become the enemy of the good. Hydrogen could be blended with natural gas in existing pipeline infrastructure on a relatively expedited basis to quickly support hydrogen demand. Over time, levels of hydrogen added to the network could gradually increase, while structural, safety, and efficiency impacts are analyzed and operations refined until a total repurposing could occur or until hydrogen-only pipelines could be built.

To advance hydrogen, policymakers must put in place the appropriate framework to ensure hydrogen transmission is safe and well documented for monitoring and information-sharing purposes. This report recommends that policymakers consider the following steps:

1. Create an independent body to serve as a data warehouse for obtaining and cataloging the physical attributes and conditions of existing pipelines to identify appropriate assets for hydrogen service.

2. Prepare a requalification standard for converting existing natural gas pipelines to hydrogen service.

3. Expedite planned replacement of natural gas distribution pipelines that are found to fall short of requalification standards.

US Support for Hydrogen in Two Acts

The Inflation Reduction Act (IRA), passed in August 2022, committed $369 billion to energy security and climate change programs, including significant investments in clean hydrogen. The IRA provided fiscal support for all levels of the green hydrogen value chain, including mining and manufacturing, renewables generation, and hydrogen production. The legislation also extended support for carbon capture and storage (CCS) and blue hydrogen.

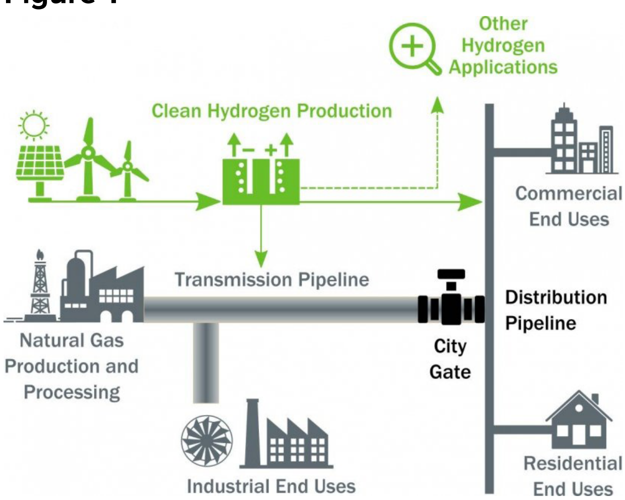
The Bipartisan Infrastructure Law, passed in November 2021, requires the Department of Energy (DOE) to invest $9.5 billion in clean hydrogen initiatives, one of the DOE's most significant investments in history. Additionally, in the fall of 2022, the DOE announced a plan to use up to $7 billion to create six to ten regional clean hydrogen hubs (H2Hubs) across the country, and to support them over five years.

Hydrogen's Biggest Head Start: The Existing Natural Gas Network

The extensive network of natural gas pipelines in the United States provides a huge opportunity for producers and consumers to potentially benefit from heightened interest in hydrogen. The network already crisscrosses the country, connecting natural gas producing areas with end users.

Traditionally, natural gas has moved from producing areas in gathering pipelines to processing centers where impurities are removed. Once processed, the natural gas is transported long distances via large-diameter, high-pressure transmission pipelines to industrial users or to cities for distribution. In cities, the gas is transported by distribution main and service pipelines to residential and commercial customers (see Figure 1).

Figure 1



The network of natural gas pipelines includes large transmission pipelines that transport fuel to industrial users and into cities, where smaller distribution and service pipelines carry fuel to commercial and residential consumers.

Source: "HyBlend: Opportunities for Hydrogen Blending in Natural Gas Pipelines," Office of Energy Efficiency & Renewable Energy, US Government, n.d., https://www.energy.gov/eere/fuelcells/hyblend-opportunities-hydrogen-blending-natural-gas-pipelines, accessed June 2023.

The United States has a vast network of more than 2.6 million miles of natural gas pipelines, including more than 17,000 miles of gas gathering pipelines, more than 300,000 miles of gas transmission pipelines, more than 1.3 million miles of gas distribution mains, and more than 950,000 miles of gas distribution service lines.[1] In addition, the United States has approximately 400 active natural gas underground storage facilities and 1,900 compressor stations.[2] If hydrogen were to be blended into the existing natural gas system it would likely enter directly into either distribution or transmission pipelines for transportation.

When considering the use of natural gas infrastructure for hydrogen service, researchers and operators must have a solid understanding of the materials and conditions through which hydrogen will flow. Almost all the transmission pipelines used to transport natural gas across the country are made of steel, which ranges in diameter from approximately four to forty-eight inches and operates at pressures between about 600 and 1,200 pounds per square inch (psi). Less than 1 percent of those pipelines are made of other materials, such as plastic or wrought iron. The lower flowing distribution pipelines, which are between approximately 0.5 and 8 inches in diameter and operating at approximately 0.25 to 100 psi, are predominantly made of polyethylene (60 percent mains/76 percent service) or steel (38 percent mains/20 percent service). There also remains a small amount of distribution pipeline mileage made of wrought or cast iron, ductile iron, copper, polyvinyl chloride (PVC), and other materials (<1 percent mains/2.8 percent service) across the country.

1 "Pipeline and Hazardous Materials Safety Administration," US Department of Transportation, n.d., https://portal.phmsa.dot.gov/phmsapub/faces/PHMSAHome?req=6306465824799078477&attempt=0, accessed March 2023.

2 "Natural Gas Compressor Stations," Homeland Infrastructure Foundation-Level Data (HIFLD), last updated December 10, 2022, https://hifld-geoplatform.opendata.arcgis.com/datasets/geoplatform::natural-gas-compressor-stations/explore?filters=eyJDT1VOVFJZIjpbIlVTQSJdfQ%3D%3D&location=44.634140%2C-112.470347%2C4.36.

Hydrogen's Biggest Headache: Converting the US Natural Gas Network to Hydrogen Usage

As many have recognized, hydrogen's characteristics as an abundant, high-energy, clean-burning fuel make it a natural contender for reducing greenhouse gas emissions. Nonetheless, there are some challenges to transporting hydrogen by pipeline that must be addressed before its use becomes universally accepted.

Those challenges relate to three specific characteristics of hydrogen: (1) its lightness; (2) its extensive flammability range; and (3) its ability to diffuse into steel, compromising the integrity of the material. Hydrogen is odorless and colorless and is often referred to as being "lighter than air." It flows at three times the rate of natural gas and is the smallest element. These characteristics mean that hydrogen can more easily escape containment and permeate pipeline materials than can natural gas.

Meanwhile, although hydrogen has a higher calorific value, its energy density is lower than that of natural gas, requiring more hydrogen to create the same amount of energy. Because of these attributes, hydrogen requires considerably more energy to compress the gas and move it through a natural gas network. Hydrogen's wider flammability range means it is easily ignitable and has higher combustion levels and flame velocity, making it especially dangerous in confined spaces.

Finally, hydrogen's embrittling effect on steel can increase crack growth rates in pipelines while reducing fracture resistance, material strength, and ductility, which can undermine the integrity of a pipeline and its components more quickly.

Meeting the challenges hydrogen poses to natural gas pipelines will require higher standards and more operational and capital costs to adapt existing pipelines for hydrogen service than infrastructure for natural gas alone. Overcoming those challenges, however, is worth the costs to expedite hydrogen usage due to its potential for lowering carbon emissions. Moreover, there are precedents for altering existing pipelines to accommodate hydrogen service and safely transport hydrogen blends in pipelines. Air Liquide, which operates the most hydrogen pipelines in the country, has converted steel pipelines from liquid fossil fuel service into hydrogen service. In addition, Hawaii Gas has been transporting hydrogen blended gas for decades. In sum, hydrogen's flammability and embrittling effects may raise the stakes for safe pipeline transportation, but not with prohibitive costs. The challenges involved in converting the existing natural gas infrastructure for hydrogen service are described below from most to least challenging.

Challenge 1: Pipeline System Materials and Condition

The first and foremost consideration for deciding whether to convert a natural gas pipeline network into hydrogen service—for either blending or hydrogen-only—is its integrity and composition. As mentioned previously, transporting hydrogen by natural gas pipeline faces challenges. Ideally, both the material composition of the pipeline itself and its integrity must be well-known before conversion.

A newly built steel pipeline for hydrogen-only service requires that close attention be paid to the strength, hardness, chemical and alloy content, and microstructure of the metal used in the pipeline.[3] The welds need to meet the same strength and toughness levels.[4] The inside surface of the pipe should also be free of "scratches, notches, carbon

3 Asia Industrial Gases Association (AIGA), *Hydrogen Pipeline Systems,* https://www.asiaiga.org/uploaded_docs/AIGA%20033_14%20Hydrogen%20pipeline%20systems.pdf, 8-21. Typical carbon steel piping should have relatively low alloy strength that is normalized for homogenous microstructures with lower sulfur and phosphorous contents to enhance toughness and with the lowest possible tensile strength consistent with the application as well as sufficient toughness. Any other alloys such as calcium, aluminum, and rare earths should also be considered into the equation.

4 National Grid performed tests on X52 pipe girth welds and found low fatigue damage, but statistically significant reductions in elongation, impact strength, and hardness. "Flow Loop Test for Hydrogen," National Grid, NIA Final Report, 2019-20, https://smarter.energynetworks.org/projects/nia_nggt0147/, 14.

deposits, and corrosion."[5] Such standards are a tall order for any new pipeline system to meet, and even tougher for an existing pipeline system. Similar issues would also need to be addressed for non-metallic pipelines. Fortunately, hydrogen is compatible with most polyethylene pipeline materials up to known higher temperature levels, and no material-based interactions or degradations have been found.[6] That means that the materials in a large percentage of the distribution network are already primed for hydrogen conversion.[7]

When converting an existing steel natural gas pipeline to blended hydrogen use, those material standards are equally important but much more difficult to ascertain. Operators might not know the age, material, condition, and operating environment of their system. Many systems were installed before pipeline safety standards were established or enforced, and others have been subject to several changes in ownership over time. Without precise knowledge of what pipe is in the ground and its condition, it may be difficult to determine its fitness for hydrogen service without significant investigation and testing.

In the absence of reliable information regarding the integrity of an existing steel pipeline system, additional research and testing are necessary to study the effects of blending hydrogen into the natural gas pipeline network.[8] Past and ongoing blending projects are discussed in the "Hydrogen's Path Forward" section of this paper. In addition, some algorithm or model must be developed to estimate the fitness of existing infrastructure to ensure it can safely accommodate hydrogen service with relative efficiency and without the risk of embrittlement and cracking over time. In its HyBlend project, the DOE is creating a tool based on the pipeline material, its age, and the proposed hydrogen blend concentration[9] that would be crucial to converting the existing natural gas pipelines to hydrogen service. Aside from the bodies of the existing pipelines, there are challenges associated with their other components and how hydrogen will affect them.

The pipeline system's integrity must be ensured not only for the pipeline bodies themselves but also for any associated piping, fittings, valves, and other components before hydrogen service can begin. Concerning these other components, their resistance to the effects of hydrogen must be top of mind. Generally, materials made of austenitic stainless steel (the most common type), pure copper, most copper alloys, and aluminum have better resistance to hydrogen embrittlement, which is described in more detail in the next section.[10] Where piping is used, any connections should ideally be welded or threaded and sealed. Likewise, any flanges or gaskets should be used in a way that minimizes leaks. Similarly, valves should be double-sealed, packed, or otherwise upgraded to prevent hydrogen leaking.[11]

Elastomer materials, which are used throughout the natural gas system, have chemical attributes consistent with their use in hydrogen service. However, as with plastics, they are subject to higher leak rates when hydrogen is transported.[12] Any component changes necessary for hydrogen service would require making enhancements to the existing network, thereby increasing costs. But some of those enhancements are probably already needed to address existing methane leaks, so upgrades would reduce both current natural gas emissions and future hydrogen leaks.

Challenge 2: Embrittlement and Corrosion

Hydrogen poses more corrosion- and embrittlement-related risks to pipelines than natural gas does. Hydrogen can reduce the strength and ductility (i.e., malleability) of many metals when it adsorbs (i.e., forms a thin layer of hydrogen gas on the surface of a metal) or diffuses into a metal, changing its microstructure. Internal corrosion caused by hydrogen gas embrittlement of a steel pipe can reduce its tensile ductility, fracture resistance, and time-to-fracture initiation, as well as increase fatigue crack growth. These properties appear to

5 AIGA, *Hydrogen Pipeline Systems, 9.*

6 Arun SK Raju et al., *Hydrogen Blending Impacts Study, California Public Utilities Commission, July 18, 2022,* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF, 11.

7 Kevin Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology, National Renewable Energy Laboratory (NREL),* October 2022, https://www.nrel.gov/docs/fy23osti/81704.pdf, 21.

8 International Energy Agency (IEA), *Global Hydrogen Review 2022,* September 2022, https://www.iea.org/reports/global-hydrogen-review-2022, 115-119.

9 "HyBlend: Opportunities for Hydrogen Blending in Natural Gas Pipelines," US Department of Energy, December 2022, https://www.energy.gov/eere/fuelcells/hyblend-opportunities-hydrogen-blending-natural-gas-pipelines.

10 Raju et al., *Hydrogen Blending Impacts Study,* 14.

11 Ibid., 23.

12 Ibid., 14.

be more pronounced in higher-strength steels.[13] The operating temperature and pressure, gas flow rate, gas impurity level, and steel surface conditions affect the risk of embrittlement. Therefore, it is imperative that operators be aware of the integrity of the pipeline materials used in hydrogen service and their limitations, as well as the nature of the gas being transported. The strength of a steel pipeline can be reduced during high-pressure hydrogen service. How much so is the subject of many past and ongoing studies.

In its 2013 study of blending hydrogen in natural gas systems, the DOE's National Renewable Energy Laboratory (NREL) determined that embrittlement of steel pipes in natural gas distribution systems raises fewer concerns because of the lower-strength steel used in the lines and the reduced flow rates.[14] As to "other metallic pipes, including ductile iron, cast and wrought iron, and copper pipes, [NREL stated] there is no concern of hydrogen damage under general operating conditions in natural gas distribution systems."[15] However, the American Society of Mechanical Engineers has determined that cast and ductile iron materials are not appropriate for hydrogen service.[16] Concerning higher-strength steel used in high-pressure transmission pipelines, NREL concluded that generally insignificant changes to those pipelines would be necessary because of hydrogen cracking when transporting up to 50 percent hydrogen blends.[17]

Ongoing studies in the aforementioned HyBlend project suggest that in the presence of hydrogen, steel fatigue is accelerated more than ten times, fracture resistance is reduced by more than half, and moving even small amounts (1 percent by volume) of hydrogen can have significant effects on steel performance.[18] While it is unclear how those factors affect pipe yield and tensile strength, they suggest an increased risk of failure on steel pipelines in hydrogen service. A 2022 review of hydrogen blending studies points to at least one study of distribution pipelines that concluded that hydrogen could be safely transported in steel pipelines because even in the instance of an initial crack that penetrates less than halfway through the wall, the 75 percent failure criterion was not reached in one hundred years.[19] While hydrogen can increase fatigue crack growth in materials, that is less likely to occur in distribution pipelines, which are operated at constant pressure.[20] In addition to embrittlement issues, there is the possibility of hydrogen-induced corrosion.[21] These HyBlend studies point to a greater risk of corrosion and embrittlement caused by transporting hydrogen in steel pipelines. Still, while the research does not delineate when deterioration and possible failure might occur, it does suggest that the risk may not be significant during the pipeline's lifetime.

Challenge 3: Compression

Because hydrogen is less energy dense than methane, for the existing natural gas transmission network to transport as much energy as it does now with a hydrogen blend, it will be necessary to add compressors and gas turbines. Otherwise, a 100 percent hydrogen system operating at the same pressure as a natural gas system would have a 15-20 percent lower energy transmission capacity. In a network carrying a blend of hydrogen and natural gas, as the hydrogen percentage increases, so does the power consumption, making the pipeline network less efficient. One study of power consumption by a pipeline compressor showed that in comparison to natural gas, moving 100 percent hydrogen would increase tenfold the required amount of work, which is the transfer of energy by a force to displace the gas.[22]

A 2020 German study on natural gas turbo-compressors concluded that they could continue to be used when transporting up to 10 percent

13 M.W. Melaina, O. Antonia, and M. Penev, *Blending Hydrogen into Natural Gas Networks: A Review of Key Issues, National Renewable Energy Laboratory,* March 2013, https://www.nrel.gov/docs/fy13osti/51995.pdf, Appendix A, 22.

14 Melaina, Antonia, and Penev, *Blending Hydrogen into Natural Gas Networks,* 23. Embrittlement is not an issue in plastic pipe, but hydrogen may deform plastic pipe. It has been found to reduce the time to pipe failure by 59 percent in pipelines transporting up to 20 percent hydrogen. See Raju et al., *Hydrogen Blending Impacts Study, 59.*

15 Melaina, Antonia, and Penev, *Blending Hydrogen into Natural Gas Networks,* 23.

16 Raju et al., *Hydrogen Blending Impacts Study,* 11.

17 Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure,* ix.

18 Raju et al., *Hydrogen Blending Impacts Study,* 67.

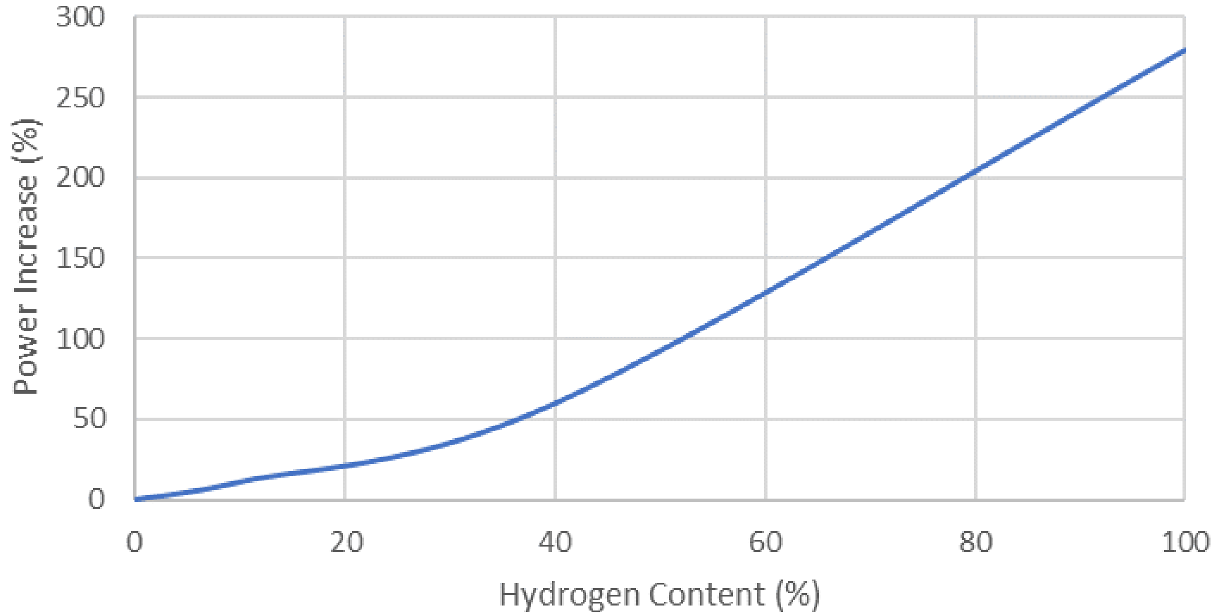
19 Devinder Mahajan et al., "Hydrogen Blending in Gas Pipeline Networks—A Review," *Energies* 15, no. 10 (2022): 13, https://www.mdpi.com/1996-1073/15/10/3582.

20 AIGA, *Hydrogen Pipeline Systems,* 57.

21 Ibid., 57.

22 Rainer Kurz, Luke Cowell, and Marc Vignal, "Hydrogen in Pipelines," *Pipeline Technology Journal*, no. 3 (2020): 71, https://www.pipeline-journal.net/sites/default/files/journal/pdf/ptj-3-2020_0.pdf.

Figure 2



Source: Rainer Kurz, Luke Cowell, and Marc Vignal, "Hydrogen in Pipelines," Pipeline Technology Journal, no. 3 (2020): 71, https://www.pipeline-journal.net/sites/default/files/journal/pdf/ptj-3-2020_0.pdf.

hydrogen without significant infrastructure changes, but moving up to 40 percent hydrogen would require adjustments to impellers, feedback stages, and gears. At a blend of more than 40 percent hydrogen, the study found that the compressor would need to be replaced. The International Energy Agency (IEA) suggested in 2022 that a natural gas pipeline completely repurposed for hydrogen service would be able to operate at only 80 to 90 percent of the energy capacity of the existing natural gas pipeline.[23] Nonetheless, it determined that the cost of conversion would still be substantially less than building a new pipeline.

Ultimately, the need to upgrade or replace existing compressors on natural gas pipelines will be a function of the amount of hydrogen carried. Lower hydrogen blends will not require new compressors. Fortunately, conventional gas turbine combustion systems that run compressors can operate with up to 30 percent hydrogen present.[24] Still, it does not appear to be a problem at lower hydrogen blends.

Challenge 4: Hydrogen Leaks

The integrity of pipelines closest to the public is of utmost importance, given the risk of injury or loss of life due to the high flammability of hydrogen. The pipelines closest to the public are distribution pipelines, especially those serving individual houses, apartments, schools, hospitals, hotels, and other highly populated businesses and institutions that use natural gas—and potentially a blend of hydrogen and natural gas—in cooking, heating, and other applications. Most of that piping is either made of polyethylene or lower-strength steel. Those pipelines are generally smaller in diameter and operate at a lower pressure than transmission pipelines. The low diameter and operating pressure of those lines mean that the most significant safety risk is usually associated with pipeline gas leakage, especially in confined spaces.

Because of hydrogen's small atomic size, it permeates through the walls of a plastic pipeline at four to six times the rate of natural gas and leaks through the threads or mechanical joints of steel

23 International Energy Agency, *Global Hydrogen Review 2022,* 113.

24 Peter Adam et al., *Hydrogen Infrastructure—the Pillar of Energy Transition: The Practical Conversion of Long-Distance Gas Networks to Hydrogen Operation,* Siemens Energy, 2020, https://assets.siemens-energy.com/siemens/assets/api/uuid:3d4339dc-434e-4692-81a0-a55adbcaa92e/200915-whitepaper-h2-infrastructure-en.pdf, 17.

pipelines at three times the rate of natural gas.[25] The volume of gas loss in 20 percent hydrogen blended distribution pipelines is estimated to be double that of a pipeline carrying only natural gas. However, the volume of loss is still considered economically insignificant. A recent study by the California Public Utilities Commission (CPUC) determined that leaks from joints, threads, cracks, and pinhole defects at a hydrogen blend of 20 percent increased leak flow rates by 10 percent.[26]

Leaks leading to explosions in the confined spaces that distribution pipelines serve are the main safety concern. Various studies have performed risk assessments of hydrogen blending into natural gas pipelines. Research has found that the gas buildup of hydrogen/natural gas blends was consistent with that of natural gas in the presence of up to 50 percent hydrogen. Still, trapped gas increased significantly beyond that point.[27] As to the severity of explosions in well-ventilated areas, the impact was only slightly different when less than 20 percent hydrogen was involved.[28] However, in confined spaces, the severity increased with up to 30 percent hydrogen present.[29] The severity of the risk was determined to be higher closer to the point of explosion, but hydrogen decreased the geographic footprint of an explosion. By comparison, IEA found that a 25 percent hydrogen blend increases the risk of hazards in a confined space of an explosion.[30]

The 2013 NREL analysis concluded that "adding low concentrations of hydrogen to existing natural gas pipeline systems, at volumes of 20% or less, results in a minor increase in the risk of ignition…[as well as] minor increases in the severity of the explosion."[31] Other studies have concluded that mixtures of 25 or 30 percent hydrogen do not significantly increase the risk of explosion.[32] The NREL study suggested the possibility that transmission lines could transport even more hydrogen without too much additional risk of explosion.[33] As to distribution mains, it concluded that transporting up to 50 percent hydrogen would create only a minor increase in overall risk, but transporting more than 20 percent hydrogen in service lines would raise the risk significantly more. The study concluded that transporting more than 50 percent hydrogen in either part of the distribution system would result in a significant increase in the overall risk. However, it appended a GTI study conclusion to state that because "distribution services are in confined spaces…[t]he overall risk is significantly increased at all hydrogen levels, and it becomes severe at hydrogen levels above 20%."[34] These studies suggest that ignition risks associated with hydrogen blends above 20 percent throughout the natural gas network would be too risky to undertake under the current circumstances.

Finally, in the United States, distribution pipelines are required to add an odorant to natural gas, which otherwise would be odorless. Since natural gas is highly combustible, odorization in distribution pipelines that run through cities and to houses and other establishments is an important safety measure. The release of natural gas, detectable by the odorant, is widely recognized throughout the country as something that should be reported immediately. The odorant in gas makes it readily apparent that a leak exists. Historically, there was no odorant for hydrogen pipeline systems, which were used primarily in industrial settings.[35] The lack of an odorant for hydrogen in distribution systems has been a significant safety concern since hydrogen is estimated to leak three times more by volume than natural gas.[36] At least one recent United Kingdom (UK) study has identified the compound of methylpropanethiol and dimethyl sulfide (Odorant NB), which is used in the UK to odorize natural gas, as a

25 Adam et al., *Hydrogen Infrastructure—the Pillar of Energy Transition,* 16-17.

26 Raju et al., *Hydrogen Blending Impacts Study,* 37. While leaky pipelines are never ideal for the environment, there is a benefit in that a hydrogen natural gas blended pipeline reduces greenhouse gas leaks because the hydrogen displaces some of the natural gas leakages.

27 Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure,* 12.

28 Ibid., 12.

29 Ibid., 13.

30 Ibid., 18.

31 Ibid., viii.

32 Mahajan et al., "Hydrogen Blending in Gas Pipeline Networks," 10.

33 Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure,* 4. Note that this report questions the notion that the transmission systems could operate at or near full capacity transporting a 5-15 percent hydrogen blend.

34 Ibid., 15.

35 Air Liquide, *Questions and Issues on Hydrogen Pipelines: Pipeline Transmission of Hydrogen,* 2005, https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/hpwgw_questissues_campbell.pdf, 23.

36 Pacific Gas and Electric (PG&E) Gas R&D and Innovation, *Pipeline Hydrogen,* 2018, https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/Whitepaper_PipelineHydrogenAnalysis.pdf, 15.

feasible odorant for hydrogen pipelines.[37] In addition, another study concluded that blending hydrogen into an existing natural gas system caused no problems in odorization of the mixed gases.[38] These studies provide reassurance that blending hydrogen into existing natural gas pipelines with odorants can be done in a way that enables leaks to be detected.

Miscellaneous Issues

In addition to the matters discussed above, many additional issues must be addressed after delivering hydrogen by pipeline. For example, if an end user is interested in obtaining pure hydrogen from a blended pipeline, the gases need to be separated, requiring additional hydrogen-capable separation facilities. Also, if an end user is a residential customer, their appliances must be capable of operating safely and reliably with a blended mix of natural gas and hydrogen. In addition, any hydrogen gas going into storage facilities must be compatible with existing natural gas storage facilities. The challenges raised by these circumstances are discussed briefly below.

Accurate Metering

An important aspect of pipeline transportation is knowing the volume of gas moving in the network for financial and safety reasons, including identifying and monitoring pipeline leaks. In a network containing one type of gas, metering and measurement should be readily obtainable using existing technologies. However, in a network containing blended gases of different concentrations, especially where one has three times the flow rate of the other, there could be an additional challenge in correctly measuring gas volume. At least one study of a pipeline transporting 17 percent hydrogen with natural gas found negligible deviations within the meter's calibration standards and little effect on meter durability.[39] More studies should be done to refine mixed gas meters to the lowest variation possible because knowledge of changes in gas volume is essential to determining whether a pipeline is leaking.[40] Since pipelines transporting hydrogen are more prone to leaks and can cause more dangerous situations, pipeline metering must be as precise as possible.

Downstream Gas Separation

The 2013 NREL study reviewed three gas separation technologies for removing hydrogen from a blended pipeline and concluded that a pressure swing adsorption (PSA) system should be used. That system runs gas through several columns filled with adsorbent materials operating at varying pressures to separate gases. PSA separators are economically feasible and commercially available for distribution pipeline pressure reduction stations at a cost of $0.30-$1.30 per kilogram of hydrogen extracted from a 10 percent hydrogen blend and for 10 percent less per kilogram of hydrogen from a 20 percent hydrogen blend.[41] While economical, at least one study has noted that it may be cheaper to have a dedicated hydrogen pipeline than to separate hydrogen from a blended system.[42] Another study suggested that this type of separation would be financially appropriate only with more than 50 percent hydrogen.[43] Other separation systems are available but not as well established. Membrane separation is possible for industrial users drawing gases directly from transmission pipelines.[44] Electrochemical separation is a potential emerging technology.[45] A 2022 NREL study also noted that it might be feasible to separate the two gases using cryogenics by condensing other gases out of the blend.[46] Again, such high separation costs would be suitable only for large-scale applications.

End-User Appliance Performance

A critical consideration regarding blending hydrogen with natural gas is whether hydrogen will operate safely and reliably in residential appliances.[47] The higher flame temperature and velocity of hydrogen

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37 Arul Murugan, *Hydrogen Odorant and Leak Detection Part 1, Hydrogen Odorant,* National Physical Laboratory (NPL), November 2020, https://sgn.co.uk/sites/default/files/media-entities/documents/2020-11/00%20Hydrogen%20Odorant%20Final%20Report%20v10.pdf, 16.

38 Marcogaz, *Odorisation of Natural Gas and Hydrogen Mixtures,* July 2021, https://www.marcogaz.org/wp-content/uploads/2021/07/ODOR-Hydrogen-and-odorisation.pdf, 13.

39 Melaina, Antonia, and Penev, *Blending Hydrogen into Natural Gas Networks,* Appendix A at 23-24; see also Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure,* 23.

40 PG&E Gas R&D and Innovation, *Pipeline Hydrogen*, Figure 5.

41 Melaina, Antonia, and Penev, *Blending Hydrogen into Natural Gas Networks,* x-xii.

42 PG&E Gas R&D and Innovation, *Pipeline Hydrogen,* 20.

43 Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure,* 27.

44 Ibid., 27-28.

45 Ibid., 28-29.

46 Ibid., 28.

47 Melaina, Antonia, and Penev, *Blending Hydrogen into Natural Gas Networks,* vii; Mahajan et al., *"Hydrogen Blending in Gas Pipeline Networks,"* 5-7.

raise concerns about overheating or causing flashbacks in existing appliances. In addition, concerns have been expressed about nitrogen oxide (NOx) releases. The 2022 CPUC study reviewed several pilots that used natural gas hydrogen blends in residential customers' appliances. It indicated that studies using 5-20 percent hydrogen blends have thus far not caused a significant safety or operational concern.[48] In addition, another 2022 review of past hydrogen blending research cited instances of 30 percent hydrogen blends not causing problems with end-user appliances.[49] It also indicated that in at least one instance, NOx emissions were decreased.[50] The question of whether hydrogen blends can be safely burned in homes is a crucial one that requires thorough vetting with studies on many appliances and brands, from vintage to modern, before more than nominal blending of hydrogen occurs.[51]

Storage of Hydrogen Blends

Beyond the pipeline network, there will be the need for any blended gas that has not been separated to utilize the existing natural gas storage network, including long-term underground storage facilities. The United States has more than four hundred underground natural gas storage facilities. It also has a few existing and planned hydrogen-only storage facilities. Storing hydrogen in existing facilities raises similar technological challenges as those related to transporting hydrogen and some new ones, as well as new geologic and microbial issues.[52] For example, questions must be answered about the extent to which existing storage facilities will be compromised because of hydrogen's attributes that might impact the integrity of the facility because those facilities are made of salt, rock, steel, or cement; what effects microbial or other impurities might have on the facilities in the presence of hydrogen; how component parts of the storage facilities will behave in the presence of hydrogen; and what effects pressure and thermodynamics will have on the storage facilities. In other words, the storage of pure hydrogen or hydrogen blends must be thoroughly researched if a transition to blended gas is to occur.

48 Raju et al., *Hydrogen Blending Impacts Study, 8; Melaina, Antonia, and Penev, Blending Hydrogen into Natural Gas Networks,* vii.

49 Mahajan et al., "Hydrogen Blending in Gas Pipeline Networks," 32-33.

50 Ibid., 32-33.

51 Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure,* 37-39.

52 Ibid., 23-26.

Potential Costs of Hydrogen Pipelines

Gauging the costs associated with transmitting hydrogen through pipelines, either existing or new, must consider several factors. For blending hydrogen into the existing natural gas pipeline system, cost depends on the amount of hydrogen added, and must include costs associated with confirming the integrity of the existing system and upgrading and/or repairing any failing components or weak segments of pipeline. In addition, increased leak monitoring and the repair or replacement of pipeline imperfections will be necessary. If substantial quantities of hydrogen are added to a transmission system, compressor investments will also probably be required. Private and public entities are actively studying scenarios to better understand what the best path forward might be.

The IEA has noted that converting natural gas transmission pipelines to 100 percent hydrogen service can cost 50-80 percent less than building a new pipeline.[53] Several German companies put the price of retrofitting their transmission lines to hydrogen service at 10-15 percent of the cost of new construction.[54] The estimated increase in compressor costs is estimated to be three times the cost for a natural gas pipeline.[55] NREL has predicted that the costs associated with inspecting and repairing pipelines carrying less than 50 percent hydrogen would increase those costs by only 10 percent.[56]

Another possibility under study is the use of pipelines for hydrogen-only distribution. Many countries are exploring the prospect of entirely repurposing natural gas pipelines to 100 percent hydrogen usage, but these studies are far from being completed.

As for building new hydrogen-only pipelines, cost estimates range greatly, depending on the material. The National Institute of Standards and Technology has estimated the costs of building hydrogen-specific steel pipelines at 68 percent more than natural gas pipelines. Estimates based on using a different grade of steel for hydrogen use reduced costs by only 31 percent.[57] These are all imperfect estimates at best. Additional costs will be necessary, but how much is unclear.

A Case Study: The Northeastern United States

The northeastern United States, an energy-hungry, highly populated region, would serve as an interesting test bed for adding hydrogen service to the existing natural gas infrastructure. The region's energy mix uses a high percentage of natural gas, presenting an opportunity to greatly benefit from emissions-lowering hydrogen blends. Additionally, its infrastructure consists of a wide range of components and pipeline materials, from plastic to cast iron, each with a different level of capacity for containing hydrogen that must be managed.

In the Northeast, the natural gas infrastructure comprises many miles of natural gas pipelines, hundreds of compressor stations, gas market hubs, gas processing plants, and gas import and export locations.[1] In addition, there are approximately forty liquefied natural gas (LNG) peak shaving and satellite plants connected to the natural gas pipeline network in the Northeast, especially along the coast, including an LNG marine terminal in Massachusetts.

The northeastern states also have the most significant number of miles of cast and wrought iron pipelines still in distribution service in the country.[2] Distribution pipelines run through city streets and backyards near the public, which in the northeastern region includes some of the most populated areas in the country. The expeditious removal of that low-quality piping material is necessary to convert it to hydrogen service safely. This challenge will lead to creative policy and technical solutions that others outside of the Northeast can draw from.

1 "Natural Gas Compressor Stations," HIFLD.

2 "Pipeline and Hazardous Materials Safety Administration," US Department of Transportation, n.d., https://portal.phmsa.dot.gov/analytics/saw.dll?PortalPages&PortalPath=%2Fshared%2FPDM%20Public%20Website%2FCI%20Miles%2FGD_Cast_Iron, accessed March 2023.

53 International Energy Agency, *Global Hydrogen Review 2022*, 7.

54 Ibid., 30.

55 Ibid., 120-122.

56 Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure,* Appendix A, 26.

57 James R. Fekete, Jeffrey W. Sowards, and Robert L. Amaro, "Economic Impact of Applying High Strength Steels in Hydrogen Gas Pipelines," *International Journal of Hydrogen Energy* 40, no 33 (2015): 10552, https://www.sciencedirect.com/science/article/abs/pii/S036031991501575X.

Hydrogen's Path Forward

Despite all the challenges facing immediate widespread introduction of hydrogen into the United States' expansive natural gas pipeline network, it may come sooner than many expect. As mentioned above, NREL is conducting a two-year HyBlend study of the technical barriers to blending hydrogen into the natural gas network, including establishing a tool to model the estimated life of existing pipelines when hydrogen is introduced.[58] This is a critical study to realistically determine the extent to which existing pipelines can transport hydrogen and how much can be safely blended into the existing natural gas network.

A 2018 research and development study funded by Pacific Gas and Electric, a US natural gas company, identified the point at which hydrogen blending is safely feasible, where adjustments and modifications are required, and where further research is needed.[59] That study concluded that the steel distribution and transmission pipelines could operate with up to 30 percent hydrogen as is, and plastic distribution pipelines could operate at close to 100 percent. For distribution systems, adjustments and modifications would be necessary for gas flow detectors, valves, and house installations to reach hydrogen blends of 50 percent. The study indicated further research of seals and connections would be essential to operate distribution systems above 30 percent hydrogen and more analysis of gas flow detectors, valves, and house installations at levels above 50 percent. However, in transmission systems, it determined that adjustments and modifications would need to be made to gas turbines at 10 percent hydrogen and compression stations at 20 percent hydrogen. Above those levels, further research would be required.

Pilot projects and research projects abound around the globe trying to determine what blending level is safe for pipelines. The United States has some historical experience blending hydrogen in natural gas systems. Since the 1970s, Hawaii Gas has been supplying up to 15 percent hydrogen via its 1,100-mile natural gas network.

In Great Britain, several studies are ongoing. Two of three UK HyDeploy pilot studies to integrate hydrogen into the natural gas network have been completed. One pilot blended up to 20 percent hydrogen into the private network of a university for more than a year.[60] The second pilot blended up to 20 percent hydrogen to supply a village with 668 homes, a school, a shop, and a church for ten months.[61] Both pilots were deemed a success.

There are many other projects in motion throughout the European Union. In France, the GRHYD project is currently providing two hundred homes in Dunkerque with a 20 percent blend of clean hydrogen via its distribution system.[62] In Germany, the WindGas project in Falkenhagen started injecting green hydrogen into the gas grid in 2013.[63] In Italy, Snam, Europe's leading operator in natural gas transportation and storage, began transporting 5 percent hydrogen in 2019 and then 10 percent hydrogen in 2020 on its natural gas transmission network in Salerno on an experimental basis.[64] The trial was deemed successful.

There are also projects in Australia spearheaded by the Australian Gas Infrastructure Group to test blending 10-100 percent hydrogen into its existing network.[65] In Canada, Enbridge, a pipeline company, is supplying a 2 percent blend of hydrogen to 3,600

58 "HyBlend Project to Accelerate Potential for Blending Hydrogen in Natural Gas Pipelines" NREL, Press Release, November 18, 2020, https://www.nrel.gov/news/program/2020/hyblend-project-to-accelerate-potential-for-blending-hydrogen-in-natural-gas-pipelines.html.

59 PG&E Gas R&D and Innovation, *Pipeline Hydrogen,* 2018, Figure 5 at 14.

60 HyDeploy, *HyDeploy Project: Project Close Down Report,* June 2021, https://hydeploy.co.uk/app/uploads/2022/06/HyDeploy-Close-Down-Report_Final.pdf, 5.

61 HyDeploy, *HyDeploy2 Project,* December 2021, https://hydeploy.co.uk/app/uploads/2022/06/HYDEPLOY2-THIRD-OFGEM-PPR.pdf, 26.

62 "The GRHYD Demonstration Project," ENGIE, n.d., https://www.engie.com/en/businesses/gas/hydrogen/power-to-gas/the-grhyd-demonstration-project, accessed March 2023.

63 Cummins Inc., "Green Hydrogen: The Power of Wind," Cummins, May 3, 2021, https://www.cummins.com/news/2021/05/03/green-hydrogen-power-wind.

64 "Snam and Hydrogen," Snam, last updated April 27, 2022, https://www.snam.it./en/energy_transition/hydrogen/snam_and_hydrogen/.

65 "Home," Australian Gas Infrastructure Group, n.d., https://www.agig.com.au/, accessed March 2023.

A gas blending station tests a mixture of hydrogen and natural gas. REUTERS/Timm Reichert.

customers in Markham, Ontario, via its current natural gas system.[66]

These and many other pilot projects are in process worldwide to identify blending limits in existing infrastructure.[67] In 2015, the IEA stated that the upper limit for integrating hydrogen into the natural gas pipeline system was in the 20-30 percent range.[68] In 2022, citing more recent studies, the IEA concluded that 5-10 percent hydrogen could be blended into transmission pipelines with minor upgrades. It also stated that up to 20 percent hydrogen could be incorporated in polymer-based distribution pipelines with some enhancements.[69] Beyond 20 percent hydrogen, the IEA said significant investment would be necessary, especially for compressors.

A recent study performed by the CPUC was more cautious about the maximum amount of hydrogen that can be moved in the natural gas system with only minor or no modifications.[70] It noted the importance of carefully studying the "intricacies of vintage pipes, natural gas composition, and operational conditions specific to each section of the natural gas network."[71] The study concluded that hydrogen blending up to 2 percent seemed viable, but beyond that, there are knowledge gaps concerning inspection, maintenance, network management, and compression. The study acknowledged successful pilot projects at blending levels above 2 percent but stated that there is a very significant knowledge gap that must be closed before considering transporting more than 50 percent hydrogen.

In sum, the blending research and literature offer a panoply of analyses and recommendations about how much hydrogen can safely be blended into the natural gas network, but with no firm conclusions. It appears there is adequate support for minimal amounts of hydrogen (i.e., in the single digits) to be transported;[72] indeed, there is significant support for transporting up to 20 percent hydrogen in existing natural gas pipelines. The final decision, however, should be based on the integrity of the pipeline network being considered for conversion.

66 "Clean Hydrogen," Enbridge, n.d., https://www.enbridge.com/about-us/new-energy-technologies/clean-hydrogen, accessed March 2023.

67 Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure,* 41; Raju et al., *Hydrogen Blending Impacts Study,* Tables 2 and 3; International Energy Agency, *Global Hydrogen Review 2022,* 118-119.

68 International Energy Agency (IEA), *Technology Roadmap – Hydrogen and Fuel Cells,* June 2015, https://www.iea.org/reports/technology-roadmap-hydrogen-and-fuel-cells, 23.

69 International Energy Agency, *Global Hydrogen Review 2022,* 115.

70 Raju et al., *Hydrogen Blending Impacts Study,* 107-108.

71 Ibid., 107.

72 Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure,* 42.

Conclusion and Recommendations

Supporting the transition toward hydrogen fuel use in the United States requires a two-pronged strategy. First, the integrity of the existing natural gas pipeline network needs to be surveyed, revalidated, and, in some instances, repaired or replaced to ensure its fitness for hydrogen service. Second, legal and regulatory ground rules must be created for the partial or complete transition of those assets. The ground rules should include the designation of lead federal agencies for siting, rates, terms of service, clarification of state versus federal responsibilities, and necessary enhancements to existing safety requirements.

To gain an understanding of both the known and unknown physical attributes (e.g., age, material, condition) of natural gas pipelines, relevant parties should create a data warehouse and collect historical documentation about the natural gas infrastructure, pipelines' current operating conditions, and the network's limitations. A consortium could be created under the auspices of a university or other third-party technical entity to lead the effort to gather this needed information to ensure data consistency and that no competitive or antitrust concerns arise. Once the entity creates a data warehouse, operators could use it to identify which parts of the network are hydrogen-ready and which assets need retrofitting, replacing, or excluding from hydrogen service. Alternatively—but less efficiently—each operator could independently assess its pipeline's readiness for hydrogen service. The results from the ongoing HyBlend project would help in making those determinations.

In addition, regulators must set standards for the requalification of pipelines to accept blended hydrogen. The guidelines should detail what steps are necessary to ensure safe operation and should include the following:

- Requirements that updated networks pass specific pipeline integrity tests, are adequately cleaned, and that all known defects have been identified before going into service
- Requirements for audits and validation that other vulnerable components of the pipeline system have been inspected and upgraded as appropriate for hydrogen service
- A thorough integrity management plan that is more rigorous than existing plans for natural gas pipelines; those plans should address, at a minimum, making enhancements to the standards for the following systems and practices looking through a hydrogen lens: supervisory control and data acquisition systems; leak monitoring and detection systems; over-pressurization reporting and response practices; maintenance practices involving non-pipe components; designation of appropriate locations for pressure regulators, emergency isolation, and shut-off valves; flaring practices; minimization of hot tapping practices; welding verification practices and procedures; in-line pipe inspections and cleaning; pipeline leak repairs; pipeline defect analysis and resolution process; emergency response plans; risk assessment and studies; other operational safety requirements; personnel safety training and qualifications; pipeline loading standards; environmental hazards analysis; and pipeline security plans

Federal and state regulators should review and update safety requirements to ensure that the above items are appropriately addressed for pipelines in hydrogen service. To support requirement updates, research into the effects of hydrogen on converted pipelines must continue. Ideally, any near misses and operational lessons learned would be liberally reported and shared throughout the converted network. Finally, in the event of a significant incident that was more destructive because of the presence of hydrogen, a root cause analysis and after-action report should be created and widely shared. The involvement of an independent resource to undertake this research and analysis and gather data would be the most pragmatic approach. Still, without such a resource, individual operators should collaborate to ensure this happens.

In recent years, hydrogen as an energy source has prudently gathered global momentum—in the form of growing attention and investment—as an enormously promising tool for providing clean energy while bolstering energy security. The vast existing network of natural gas pipelines throughout the United States presents a near-term opportunity for addressing the problem of hydrogen availability while longer-term solutions are evaluated. Filling the gap in knowledge on the safety of hydrogen service via natural gas pipelines, and creating a regulatory and policy environment favorable to this approach, will be critical to bringing it to fruition.

About the Author

Cynthia Quarterman is a distinguished fellow with the Global Energy Center at the Atlantic Council. Quarterman served as the administrator of the US Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) from 2009 until 2014. She has been a key policymaker in energy development, safety, environmental and transportation issues since the Clinton administration.

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