

INVESTING IN THE US NATURAL GAS PIPELINE SYSTEM TO SUPPORT NET-ZERO TARGETS

**BY ERIN M. BLANTON, DR. MELISSA C. LOTT,
AND KIRSTEN NICOLE SMITH
APRIL 2021**

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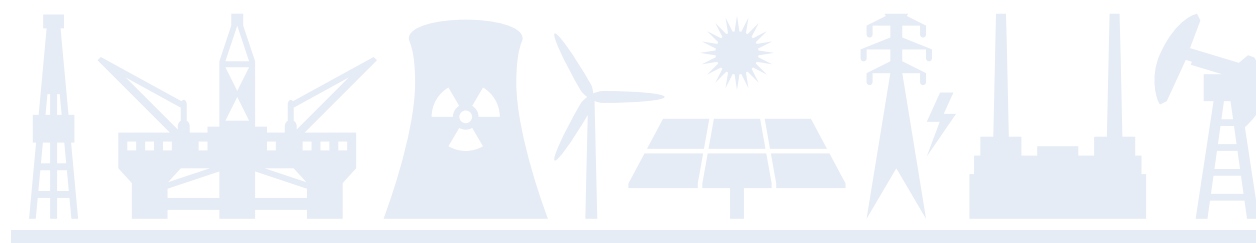
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EXECUTIVE SUMMARY

The Biden administration's move to bring the United States back into the Paris Agreement and lower greenhouse gas emissions to address climate change will, if carried through, lead to a reduction in fossil fuel consumption. Cutting back on the burning of coal, oil, and natural gas will be critical to transitioning the country to the lower-carbon energy system it needs to achieve decarbonization targets. But while it may seem counterintuitive, investing more in the domestic natural gas pipeline network could help the US reach net-zero emission goals more quickly and cheaply. Fortifying and upgrading the system could prepare the existing infrastructure to transport zero-carbon fuels as they become available and, in the meantime, reduce harmful methane leaks from natural gas.

Studies by energy agencies, universities, and the industry that model future US natural gas consumption consistently show continued use of natural gas for at least the next 30 years, even in scenarios where the country achieves net-zero targets by midcentury. There is no quick replacement for gas in the US energy mix. And for many of the needs natural gas currently meets, the eventual replacement may be zero-carbon gaseous fuels (e.g., hydrogen, biogas). These fuels may play a significant role in supporting reliability and making the energy transition more affordable—but they, too, will require a pipeline network for efficient delivery to markets and end users.

Building new pipelines is a time-consuming and costly process, especially when added to all the other infrastructure needs associated with the energy transition. When possible, adjusting existing infrastructure—already permitted and built—can help minimize the costs and accelerate the speed of the transition. The US has 2.5 million miles of natural gas pipeline infrastructure across the country, which, with investment, could be upgraded to cut emissions and be retrofitted for future transport of cleaner fuels.

However, investments in pipeline infrastructure have drawn concern that they would lock fossil fuels into the US energy mix for a longer period of time and work against the energy transition. Such concerns are understandable given the contribution of fossil fuels to the global climate crisis. But retrofitting and otherwise improving the existing pipeline system are not a choice between natural gas and electrification or between fossil fuels and zero-carbon fuels. Rather, these investments in existing infrastructure can support a pathway toward wider storage and delivery of cleaner and increasingly low-carbon gases while lowering the overall cost of the transition and ensuring reliability across the energy system. In the same way that the electric grid allows for increasingly low-carbon electrons to be transported, the natural gas grid should be viewed as a way to enable increasingly low-carbon molecules to be transported.

This paper, part of the work by Columbia University's Center on Global Energy Policy on natural gas and the energy transition, examines projections of continued natural gas use and the zero-carbon fuels that are poised to become a bigger part of the energy mix. It details the state of the existing US natural gas pipeline network and trends within this segment of the market, as well as technical considerations for moving new, zero-carbon fuels through



the system. The findings, combined with potential net-zero goals, lead to recommendations for curbing greenhouse gas emissions caused by leakage in the existing network, as well as opportunities to refurbish sections to carry increasing levels of cleaner fuels. It focuses on policy options that will minimize environmental impacts and maximize economic benefits.

These options fall into two main categories: changing regulations on methane leak detection and repair to make the existing pipeline network as low emissions as possible while it still transports natural gas, and expanding on existing regulatory authority to allow for retrofitting the system for more hydrogen usage, along with increased R&D funding to test the integrity of the pipeline system with greater levels of hydrogen and other zero-carbon fuels. Specific recommendations include the following:

- Accelerate the pace to replace remaining cast-iron pipelines—which constitute a small percentage of the existing infrastructure but are responsible for an outsized percentage of methane leaks and are also incompatible with transporting hydrogen—and mandate replacement of aging pipelines.
- Adopt state-level methane reduction targets for gas utilities.
- Update federal pipeline standards to require annual inspections, change the criteria for which leaks need to be repaired, and require all leaks be reported.
- Conduct state-level inventories of the metallurgy in their pipeline infrastructure to identify parts most compatible with increased hydrogen usage, while questions surrounding how best to blend hydrogen and other zero-carbon fuels into the system undergo further study. Require that mains replacement programs use hydrogen-compatible plastic pipes.
- Consider specific rate add-ons that allow states to modify the system to accommodate hydrogen if those modifications can be made without an undue burden on ratepayers, especially lower income groups.



INTRODUCTION

The energy transition has a significant but surmountable infrastructure problem. The United States will need to make large investments in new infrastructure in order to transition to a net-zero economy, a process that will face challenges from long lead times due in part to financing and permitting issues. Utilizing the nation's existing and proven natural gas pipeline system could be a low-cost part of a zero-carbon energy solution within the time frame outlined in the Paris Agreement. However, investments in this infrastructure have drawn concern that they would lock fossil fuels into the US energy mix for a longer period of time and work against a zero-carbon transition.

Such concerns are understandable given the contribution of fossil fuels to the global climate crisis. However, retrofitting and otherwise improving the existing pipeline system are not a choice between natural gas and electrification or between fossil fuels and zero-carbon fuels. Rather, these investments in existing infrastructure can support a pathway toward wider storage and delivery of cleaner and increasingly zero-carbon gases while lowering the overall cost of the transition and ensuring reliability across the energy system. In the same way that the electric grid allows for increasingly low-carbon electrons to be transported, the natural gas grid should be viewed as a way to enable increasingly low-carbon molecules to be transported.

Failing to invest in the US natural gas pipeline network ignores some critical US energy realities. Natural gas currently provides a huge volume of energy that can be stored for long durations. Due to a lack of readily available zero-carbon fuel substitutes, the nation is likely to require natural gas in its energy mix for decades to come, even if the absolute amount declines as technology resolves those issues and accelerates the transition to zero-carbon gases. Achieving zero emissions in this fuel constrained situation will require extensive use of carbon capture and sequestration (CCS) in power generation and industry.

In the transition to zero-carbon energy systems, one of the fuels that is reasonably expected to displace natural gas is hydrogen, which will also need to be shipped by pipeline in order to keep costs low. The expansive nature of the current natural gas grid ensures that low-carbon and zero-carbon fuels, such as hydrogen, biomethane, and synthetic methane, could reach all sectors of the economy through existing infrastructure, including those sectors that are broadly considered “hard to abate,” such as industrial processes (cement, steel production), the fertilizer industry, and heavy-duty transport where electrification is not currently a viable pathway to zero emissions.

The fact that hydrogen has a lower energy density relative to natural gas means that about three times the volume of hydrogen needs to be delivered to provide the equivalent heat content as natural gas. Even a 20 percent hydrogen blend rate in our current natural gas system would actually utilize approximately 40 percent¹ more capacity than is currently available in the US pipeline network to provide the equivalent energy. In this and similar cases, additional pipeline capacity would need to be built to transport hydrogen, especially when hydrogen production is not located near existing natural gas pipelines. The existing



gas network and additional capacity designed for zero-carbon fuel use should be viewed as complementary tools in meeting a net-zero future.

In the near term, replacement of older pipelines and distribution mains in the existing natural gas pipeline network, as well as regulations on methane leaks and repairs, can cost-effectively reduce cumulative greenhouse gas emissions. Over the next one to two decades, the existing system can be retrofitted to be compatible with low- and zero-carbon fuels (e.g., hydrogen blends) while significant carbon capture and sequestration capacity can be added to existing natural gas-fired power plants and industries. With a midcentury net-zero target, the US has time to test and adapt the natural gas system for increased blending of hydrogen and develop ways to reach the presumed 20 percent threshold of hydrogen blending into the existing network, as well as find ways to increase this threshold. By midcentury, the gas grid could ultimately be transporting 100 percent carbon-free fuels through a combination of natural gas with CCS, biomethane, and zero-carbon hydrogen.

The challenge, however, will be weaning industry and end users off of natural gas and toward these zero-carbon or lower-carbon fuels despite the availability of cheap natural gas. Getting end users to opt for zero-carbon fuels is therefore expected to require significant policy support. In the same way renewable portfolio standards drove renewables development, a zero-carbon target could drive increased use of zero-carbon gaseous fuels (e.g., natural gas with CCS and carbon capture, use, and storage [CCUS]; biomethane; and zero-carbon hydrogen) and investments across the United States in existing infrastructure.

Modernizing and adapting the US natural gas pipeline network will require a concerted effort and significant short-term investments, but making use of the infrastructure already in place could offer a prime route for speeding up and cost-effectively making the considerable changes needed to fully decarbonize the energy sector—while also enabling a just transition for communities that have invested in and rely upon these systems. Such investments would come from the private sector, but there is a significant role for the public sector in driving the investments and making them economic. Absent action in the public sector, it is highly unlikely the US will meet its goal of being net-zero by 2050.

This paper explores the potential role of existing US natural gas pipeline infrastructure in realizing a zero-carbon energy future and discusses potential actions from policymakers to enable and facilitate investments toward such a goal. It recommends pursuing two primary pathways to support progress toward net-zero targets: preventing leaks in the existing pipeline and distribution system and upgrading the existing system to transport increasing levels of zero-carbon gases.

Section 1 discusses current natural gas use and future demand scenarios for natural gas, both with and without CCS, as well as future demand for other zero-carbon gaseous fuels in order to contextualize the utility of the pipeline network in accelerating economywide decarbonization. Section 2 provides an overview of the existing US pipeline network, including a discussion of its breadth and recent cost trends. Section 3 explores which low and zero-carbon gases could utilize the existing pipeline system to support the energy transition and includes an overview of technical considerations as higher levels of zero-carbon gases are blended into the system.



Section 4 offers recommendations to policymakers for actions that could improve the environmental footprint of existing pipelines and ensure that this network can support a safe, rapid, and affordable transition to a net-zero economy. The recommendations focus on actions that could make the existing pipeline network as low emission as possible through regulatory changes on methane leak detection and repair. They also discuss how to expand regulatory authority to allow for retrofitting the transmission and distribution system for more hydrogen usage in the pipeline network and the need to increase R&D funding to test the integrity of the pipeline system with greater levels of hydrogen and other zero-carbon fuels.



SECTION 1. CURRENT NATURAL GAS CONSUMPTION AND FUTURE SCENARIOS

Considering current natural gas use and future projections for both natural gas and zero-carbon gaseous fuels transported by pipelines helps to contextualize the role that existing pipeline infrastructure might play in a decarbonizing and electrifying economy. It also highlights the important role that CCS will play in the US meeting net-zero scenarios. This section begins with an overview of current natural gas consumption and recent trends and is followed by an overview of projected future consumption across an array of scenarios modeled in outside studies, acknowledging key sensitivities in these scenarios.

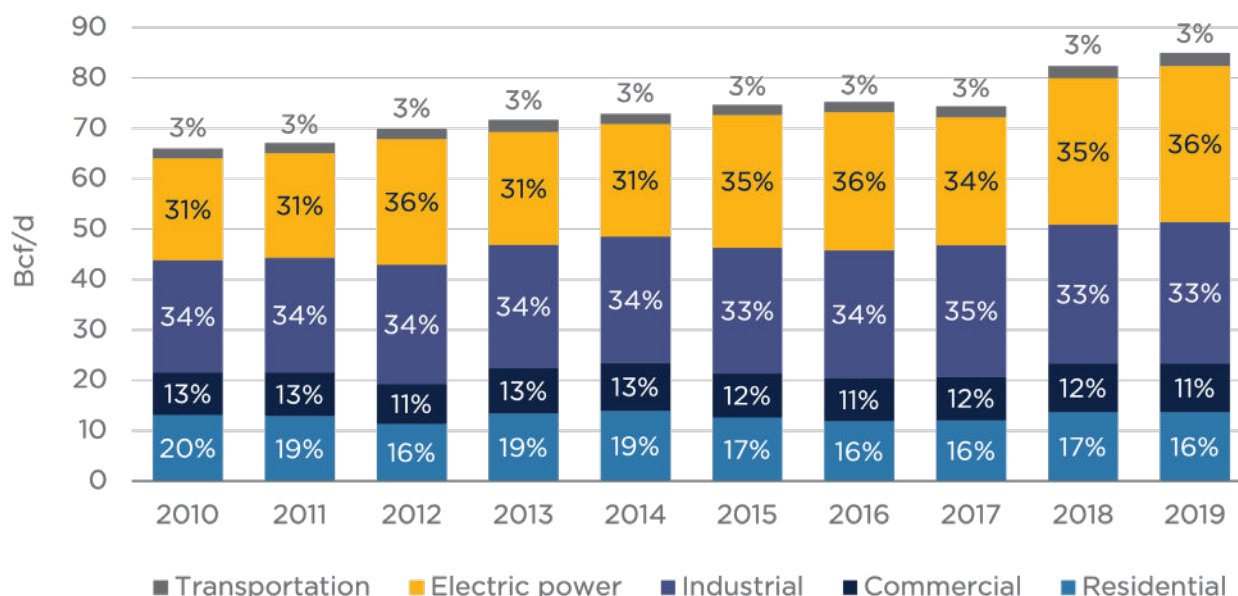
Current Natural Gas Consumption

Natural gas currently accounts for about a third of electricity generation, a third of industrial energy consumption, a quarter of residential energy consumption, 20 percent of all commercial energy consumption, and 3 percent of transportation sector consumption in the US.²

In power generation, low natural gas prices have led to increasing use of natural gas, both in existing plants and new builds, displacing coal-fired power plants. In industry, natural gas is used for process heating, in combined heat and power systems, and as a feedstock to produce chemicals, fertilizer, and hydrogen. In commercial and residential buildings, natural gas is used for an array of applications, including space and water heating, refrigeration and cooling equipment operation, cooking, and drying clothes. About 48 percent of US homes (179 million people) currently use natural gas for one or more of these purposes.³ In transportation, natural gas is currently used as a vehicle fuel in the form of compressed natural gas and liquified natural gas (LNG).⁴

The three dominant uses for natural gas in the US are electricity generation, industrial heat, and residential plus commercial consumption—and total consumption of natural gas has grown by 25 percent in the last decade (figure 1).



Figure 1: Total US natural gas consumption by sector (includes sector share)

Note: Preliminary data for 2019.

Source: US EIA monthly energy review

In addition to domestic production and consumption, the US also imports and exports natural gas and has been a net exporter of natural gas since 2017. In 2019, the US imported a total of 7.5 Bcf/d via pipeline from Canada and LNG imports. The US exported a total of 12.8 Bcf/d in 2019.⁵ Exports of pipeline gas to Mexico were 5.1 Bcf/d, and exports of pipeline gas to Canada were 2.7 Bcf/d. Exports of LNG were 5 Bcf/d. Exports are reasonably expected to be an important source of future demand for US natural gas producers. There is the potential for the expansion of US exports to undermine decarbonization goals and could drive investment in natural gas infrastructure that is not focused on transportation of zero-carbon fuels. It will therefore be necessary for the Federal Energy Regulatory Commission (FERC) and other regulatory agencies to ensure that US natural gas exports are also on track to fit into a decarbonizing future. The same focus would need to be put on net-zero emissions for export volumes as it is for domestically consumed volumes. US exporters would need to start positioning themselves as exporters of carbon neutral LNG cargoes via offsets and mitigation of emissions along the value chain.

Of the 91.2 Bcf/d of natural gas that the United States produced in 2019, net exports accounted for 5.8 percent (5.3 Bcf/d).⁶ That share is projected to rise over the coming years from US LNG export capacity and pipeline capacity to Mexico that is under construction. The extent to which US export capacity will continue to expand in coming years after the impact of COVID-19 on LNG investment is outside the scope of this paper but has been addressed in previous research.⁷



Because of this widespread sectoral usage of natural gas within the US and increasing demand from outside the US, it is reasonable to expect that it will be more complicated to move the US economy off of natural gas than it has been to move away from coal. Coal accounts for 11 percent of total US energy consumption, but 92 percent of all coal is consumed in the power sector with the rest accounting for a small share of industrial use, such as coking plants. Conversely, as previously discussed, natural gas is used across the entire energy sector.

Future Natural Gas Consumption Scenarios

An array of organizations has produced scenarios that explore potential future demand for different supply-side technologies and fuels, including natural gas and other gaseous fuels (e.g., zero-carbon hydrogen, biofuels).⁸ At a high level, a primary takeaway of these scenarios is that the US continues to use natural gas even in scenarios where the US achieves net-zero targets by midcentury. Furthermore, even in scenarios where the economy moves away from natural gas use, gaseous fuels (e.g., zero-carbon hydrogen, biogas) still play significant roles in supporting reliability and making the energy transition more affordable. Having some systems, such as industrial and residential heat, remain nonelectrified and instead supplied by gas molecules could lend a very important component of reliability, providing backup should electrical systems go down.

Overall, these scenarios consistently show continued use of natural gas over the next 30 years. Even in deep decarbonization scenarios, analysis shows natural gas continuing to play a significant role in the energy system, particularly in power generation (assuming that CCS technologies can be deployed) and industry (e.g., as a feedstock). In many scenarios, natural gas consumption grows to meet energy demand in key sectors as an alternative to other higher-carbon fuels.

While a natural gas future is by no means locked in at a particular level across the range of possible scenarios, understanding the reasons why these modelling exercises continue to project future gas consumption—cost, cross-sectoral consumption, and lower-carbon firm power capacity—is worthwhile when designing policies to meet these deep decarbonization targets. Furthermore, by comparing current versus past projections, it is possible to see how underlying assumptions have changed and what that could mean for future scenarios.

These observations are drawn from an examination of an array of studies, including the 23 scenarios produced by the US Energy Information Administration (EIA) for its Annual Energy Outlook. Because some see the EIA as bullish on natural gas demand, and because the EIA does not produce a net-zero scenario in its Annual Energy Outlook, the authors subsequently review in this section a number of scenarios produced by other organizations, such as the International Energy Agency (IEA), BP, and Princeton University, that consider deep decarbonization pathways.⁹ The authors also discuss a recent study by UC Berkeley, which focuses particularly on decarbonization of the power sector in line with the Biden-Harris Administration's proposed goal of eliminating power-sector emissions in the United States by 2035.



US Energy Information Administration

In the EIA 2020 reference case scenario, US natural gas demand remains relatively flat through 2030 due to a combination of declining consumption in the power sector and moderate growth in industrial sector demand. However, after 2030, this scenario projects consumption growth of almost 1 percent per year on average as gas demand in the industrial sector and power sector rises. By 2050, the EIA projects that US consumption will have risen to 100 Bcf/d compared to 85 Bcf/d in 2019.¹⁰ The breakout by sector of the EIA 2020 reference scenario is discussed in Appendix A.

The EIA's long-term projections for natural gas consumption have risen significantly over the last few years. In the EIA reference case from 2013,¹¹ gas consumption was projected to increase from 25.6 trillion cubic feet (TCF) (70 Bcf/d) to 29.5 TCF (80.9 Bcf/d) by 2040. However, six years later (i.e., in 2019), US natural gas consumption had already surpassed the EIA's projection for 2040.

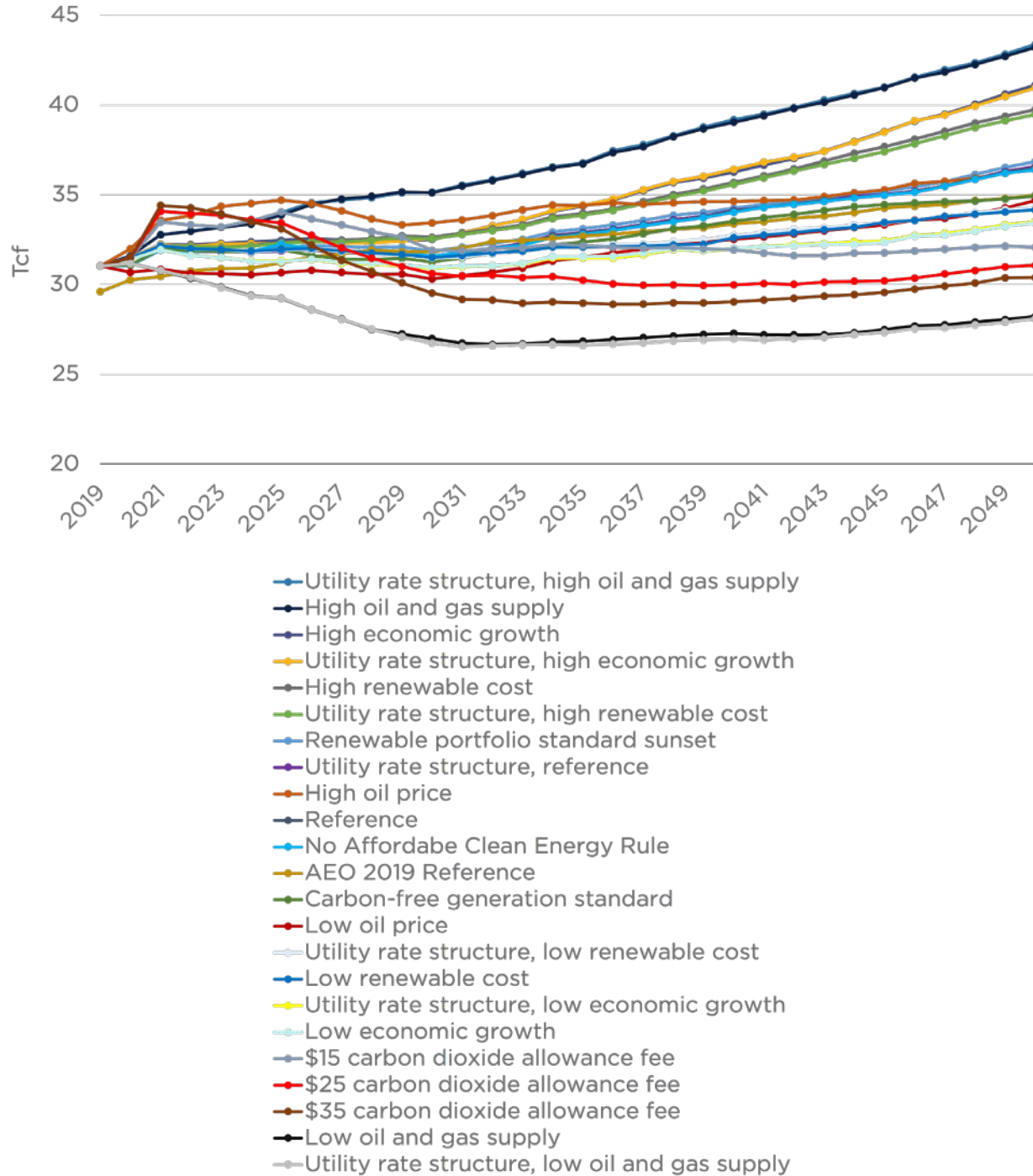
Examination of the EIA's scenarios beyond the EIA reference case shows that natural gas consumption remains in line with the reference case over the next three decades, even with a carbon-free electricity generation standard, a low oil price, and low renewable cost scenarios.

Scenarios that include a carbon-free electricity generation standard and a \$15/ton CO₂ price both result in a higher consumption of natural gas. This result is driven by significant coal-to-gas switching. Despite recent coal plant retirements, the US still has 229 GW of coal-fired capacity.¹² Those plants supplied 19.3 percent of US electricity demand in 2020.¹³ In these scenarios, much of this capacity is replaced by natural gas, with its lower carbon footprint. The only scenarios in which natural gas demand is lower in 2050, compared to current consumption levels, are those that either assume low oil and gas supplies or where there is a carbon price of \$25/ton or \$35/ton.

Across these scenarios, the lowest level that gas consumption falls to is 26.6 TCF (73 Bcf/d) in 2031 (in the utility rate structure and low oil and gas supply scenarios) before rising to 28 TCF (76.7 Bcf/d) by 2050.¹⁴



Figure 2: EIA AEO total US natural gas consumption by scenario



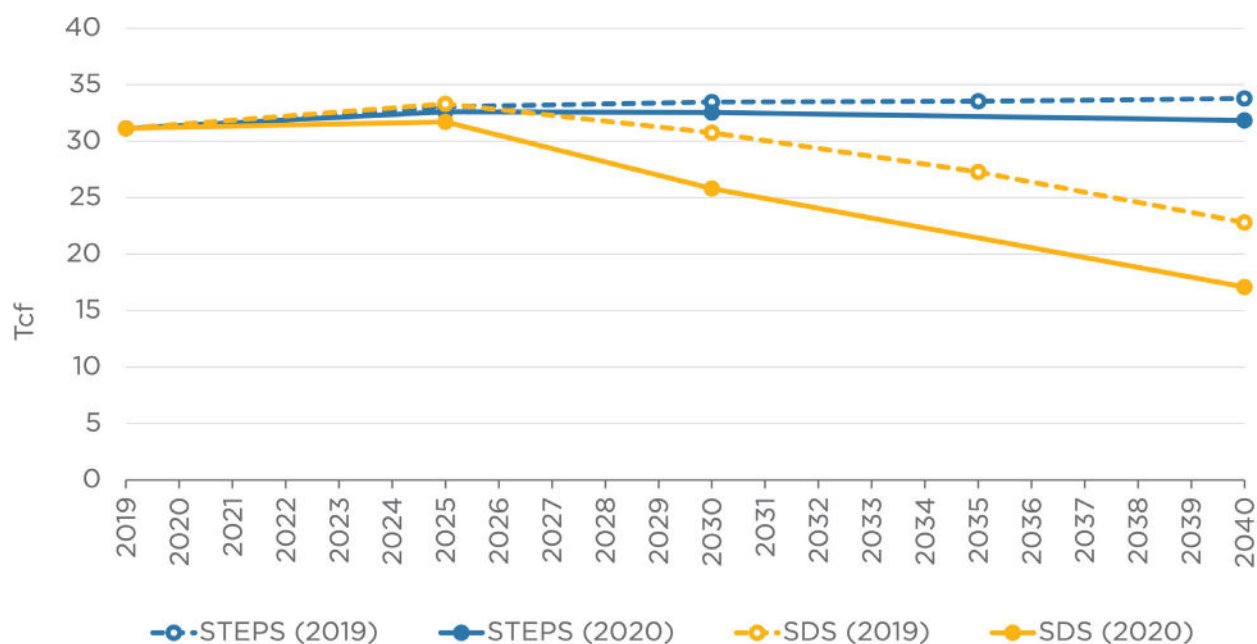
Source: US EIA Annual Energy Outlook 2020, <https://www.eia.gov/outlooks/archive/aeo20/>



International Energy Agency

As previously mentioned, the EIA 2020 projections are more bullish on long-term natural gas consumption than the IEA scenarios in 2020.¹⁵ The IEA has made significant downward revisions to its long-term gas projections since 2019 (figure 3). In the IEA's Stated Policies (STEPS), US natural gas consumption only increases marginally by 2040 to 31.8 TCF (87 Bcf/d).

Figure 3: IEA WEO total US natural gas consumption by scenario



Source: IEA World Energy Outlook 2020, <https://www.iea.org/reports/world-energy-outlook-2020>

The IEA Sustainable Development Scenario (SDS) is in line with the UN sustainable development goals and Paris Agreement targets (the EIA currently does not run a Paris aligned scenario, something that is likely to change under the new Biden-Harris Administration). This scenario results in a significant drop in natural gas consumption after 2025—with consumption falling to 17 TCF (46.6 Bcf/d) in 2040, well below any of the EIA scenarios and a significant drop from the SDS 2019 projections of 22.8 TCF.

When comparing the 2020 IEA SDS scenario to the previous 2019 projections, about 80 percent of the reduction in gas demand between these scenarios comes from decreasing consumption in the power sector. The IEA projects that post-COVID-19 recovery will follow along the lines of its sustainable development recovery scenario.¹⁶ Generation from solar is notably higher than in the 2019 scenario (due to the assumption of continued low-cost financing for solar), which eats into the share of gas-fired generation. As a result, gas-fired power generation peaks around 2025 and then declines.



As the fuel composition of power generation changes, it is likely that utilization of gas generation will shift from baseload to more of a balancing fuel for renewables in this scenario. However, pipelines would still be needed under these conditions. Of note is that total gas capacity in 2040 was not similarly revised downward in the 2020 SDS versus the 2019 SDS, as the gas plants still act as an important source of flexibility. However, their capacity factors (and therefore amount of gas consumed) are much lower than in the IEA's 2019 scenario.

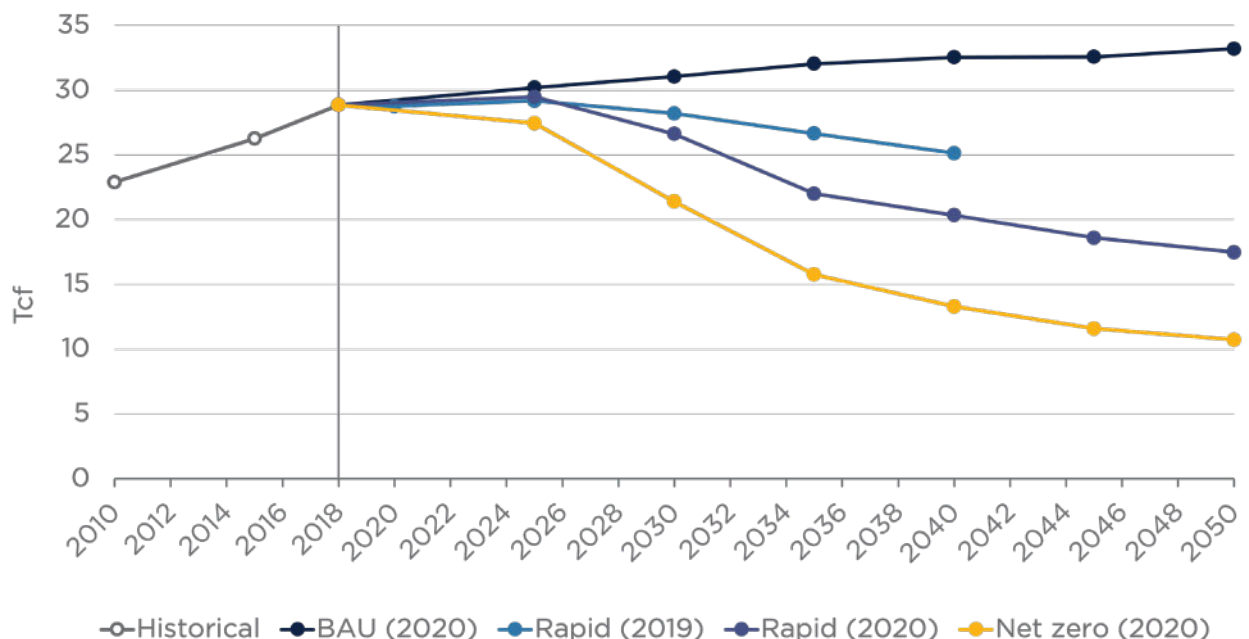
The SDS is based on an ambitious transformation of the energy sector with significant expansions of solar PV capacity, as well as battery storage. It also assumes that nuclear plants will see lifetime extensions to maintain operations. Carbon capture, utilization, and storage (CCUS) also scales up significantly by 2030, resulting in a stronger role for natural gas in this net-zero future scenario.

But importantly, nearly a quarter of investment in the SDS in gaseous fuel supply goes to biomethane and low-carbon hydrogen by 2040 compared with around 1 percent globally today: these sources could use the pipeline infrastructure currently used for natural gas.

BP

Within the energy industry, BP prepared three scenarios in 2020: the business as usual (BAU) scenario, the rapid transition scenario, and a new net-zero scenario. In the BP Outlook, the BAU scenario projects gas demand increasing to 33 Tcf by 2050 (figure 4).¹⁷

Figure 4: BP total US natural gas consumption by scenario

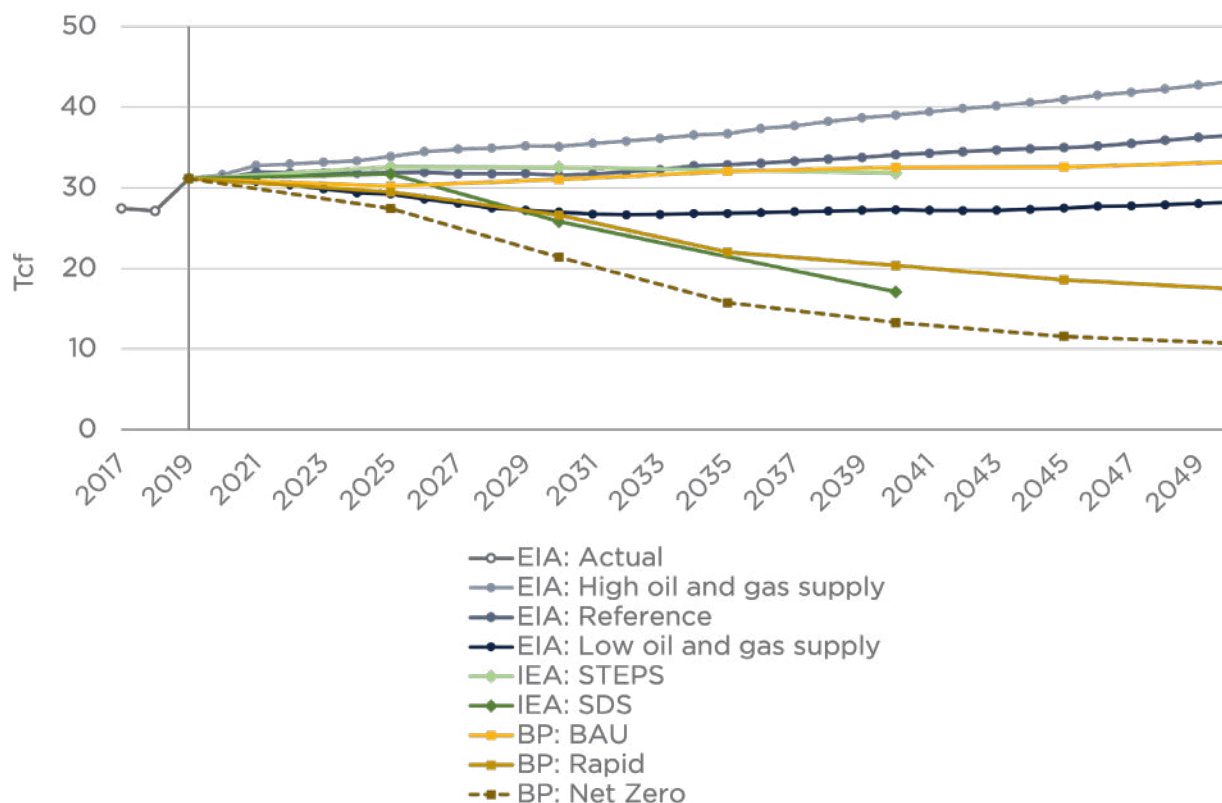


Source: BP Energy Outlook 2020, <https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2020.pdf>; BP Energy Outlook 2019, <https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2019.pdf>



Like the IEA, however, BP's rapid transition scenario has also been revised down significantly from 2019, with gas demand falling to 17.5 TCF in 2050, a decade after the IEA projections in their similar scenario. The new BP net-zero scenario has a far steeper decline in natural gas demand down to 11 TCF (30 Bcf/d) by 2050 (figure 5).

Figure 5: Total US natural gas consumption under the EIA, IEA, and BP 2020 scenarios



Source: US EIA 2020; IEA 2020; BP 2020

Combined, these scenarios by the EIA, IEA, and BP produce long-term natural gas demand levels across the range of 11 TCF to 43 TCF in 2050. It is worth noting that even in the most aggressive projections, even 20 years from now, in 2040, there is still between 13 and 17 TCF of natural gas flowing through the US pipeline system, 50 percent of current volumes. Furthermore, net-zero scenarios include rapid growth in biogas and hydrogen consumption, which all point to continued high utilization of the existing US natural gas pipeline system.

As previously mentioned, over time and pending significant cost reductions, natural gas can potentially be replaced with zero-carbon fuel alternatives (e.g., green hydrogen, biomethane). Combined with the previously discussed scenarios' results, it is reasonable to expect that there is both a need to continue investment to maintain this infrastructure in the near-term while also ensuring that it is compatible with both natural gas and zero-carbon fuel alternatives in the future.



UC Berkeley's 2035 Report

Other scenarios that have focused on deeply cutting emissions in the power sector have also shown continued use of natural gas. For example, in September 2020, UC Berkeley's 2035 report, which targeted a 90 percent "clean" power sector by 2035 in the United States, found that existing natural gas plants still played a critical role in supporting reliable grid operation in that year.¹⁸ In this scenario, natural gas power plants are particularly critical in July and August due to increased air conditioning loads at the same time that the country sees decreasing wind production. A subsequent white paper by these authors explored a number of options for eliminating the remaining 10 percent of emissions from the power sector, including retrofitting existing natural gas plants with CCS and various green hydrogen technologies that are "inherently speculative" at this time.¹⁹ Solutions that rely on retrofitting existing power plants, located all across the United States, ultimately rely on continued use of the pipeline system to supply adequate feedstock, even if in a reduced, peaking role.

Princeton Net-Zero America Potential Pathways

Potential Pathways, Infrastructure, and Impacts study taking into account cost, technology, and feasibility trade-offs typically assumed in high electrification and deep decarbonization pathways.²⁰ Over this study's five scenarios, which ranged from a high electrification only (E+) scenario to a 100 percent renewable, no fossil fuels by 2050 (E+, RE+) scenario, four of the five pathways continue to consume fossil fuels beyond 2050. While total electricity demand increases in all five scenarios (up between 115+ percent to 300+ percent relative to 2020), natural gas consumption declines between 50 percent and 100 percent by 2050.

Natural gas power generation capacity retirements and additions vary across the five scenarios, with all scenarios requiring capacity additions to 2040, including the aforementioned 100 percent renewables scenario with no fossil fuel consumption beyond 2050. The Princeton study is also interesting in that pipeline gas is only full decarbonized in the RE+ scenarios (100 percent primary energy from renewables). This is because natural gas is the cheapest fossil fuel with the lowest carbon content and therefore is one of the last blends to be decarbonized.

In each of the five scenarios, it is notable that a significant capacity of gas without carbon capture remains on the system (i.e., the capacity of CCGTs and CTs is not significantly reduced when compared to the reference scenario). As the Princeton study notes, this is because these gas power plants play a critical role within high wind and solar energy scenarios by providing a limited amount of sustained peaking capacity, often seasonal, to maintain system reliability.

These types of reliability events are highly uneconomic for battery storage to meet either because of how infrequent they are or because of the large number of consecutive hours with an energy deficit. Gas-fired power plants without carbon capture have very high variable cost when accounting for the marginal cost of carbon emissions. But they remain economic in these scenarios because of the infrequency of dispatch.

Projections can certainly shift, as evidenced by the IEA and BP outlooks in 2020 compared to 2019. But despite these variations, scenario projections show a consistently strong role



for natural gas and other gaseous fuels (e.g., zero-carbon hydrogen, biomethane) in the US energy system across multiple sectors. The drivers of these results are numerous and include the complementary nature of these gas resources and renewables, as well as their ability to be stored for long periods of time. Use of firm and dispatchable resource—including natural gas power plants with CCUS—to support both system reliability and affordability consistently lower the cost of deep decarbonization.²¹

It is important to note, however, that deep decarbonization scenarios typically assume the availability of carbon capture and storage with and without utilization (CCS and CCUS) technologies to further reduce the carbon footprint of natural gas use in order to achieve net-zero emissions. They also assume that the industry can significantly reduce flaring and leakage of gas in upstream production and throughout the pipeline systems, which is not currently on track (see box 1).

Flaring and methane leakage

Flaring is a common practice at oil and gas facilities. When not all of the natural gas (which is mostly methane) that surfaces during oil or gas extraction can be used, it is burnt off in flares so that the energy can be released as carbon dioxide, a gas with less warming potential than methane.

Methane emissions from oil and gas operations accounted for around 28 percent of the total methane emissions in the US in 2018, behind agriculture's 38 percent share, according to the Environmental Protection Agency.²² Most of those emissions come from unintentional leaks, vented emissions, intermittent emissions, and unlit or malfunctioning flares.²³

A wide variety of well-known and proven technologies are available to reduce methane emissions from oil and gas operations (e.g., vapor recovery units, low bleed controllers, and electric pump systems.) Consistent maintenance programs to replace seals and transitioning to low emission compression are other options. Cost-effective mitigation methods include improved leak detection and repair via vehicle-based systems, stationary monitoring systems, aerial monitoring, and imaging technologies.²⁴

Reducing oil and gas related methane emissions is relatively cost effective,²⁵ especially as methane has commercial value and when captured can usually be monetized. In the US natural gas losses from methane leakage amount to about \$2 billion per year and substantially erode the climate benefits of natural gas if not addressed.²⁶

Without CCS and CCUS, as well as targeted efforts to reduce flaring and leakage, natural gas's continued use would be contingent on corresponding offsets (e.g., direct air capture, nature-based solutions), many of which are open to criticism. Questions remain about double counting, the lack of independent verification, and the permanence of offsets, all of which lead to concerns that they can be a form of "greenwashing."²⁷



Carbon Capture and Storage

The value of pipeline infrastructure in the context of this analysis is its ability to support deep decarbonization of the energy system by moving fuels, both natural gas and zero-carbon gaseous fuels, around the country efficiently and reliably. In turn, it is critical to understand the application of carbon capture and storage, both with and without utilization (CCS and CCUS). A number of studies show that application of CCS to natural gas power can lead to substantial and rapid decarbonization, in part because of its ability to use existing infrastructure and in part because it is a lower cost option than relying on just renewables or efficiency improvements in key markets and applications.²⁸

Carbon capture systems concentrate CO₂ to 95 percent or greater purity, which is then transported either to qualified geological storage systems (e.g., depleted oil and gas reservoirs, deep saline formations, coal beds that can't be mined, and shale basins) or utilized to produce goods.

CCS opportunities exist at large coal and natural gas-fired plants, major industrial sources such as cement plants and synthetic fuel plants, and fossil-based hydrogen production facilities. Carbon capture systems could be retrofitted onto existing facilities in many cases, and blue hydrogen (hydrogen produced with natural gas systems that have carbon capture) could be produced on-site and fed into new and existing natural gas power plants.²⁹ This approach has the particular advantage of using existing pipelines and plants with minimal changes.

Existing CCS technology can capture approximately 80-90 percent of CO₂ produced during power generation.³⁰ As a result, CCS has been identified as a key component in decarbonizing the US power sector. In addition, some newer systems³¹ produce pure CO₂ streams ready for use or permanent geological disposal that would effectively result in 100 percent CO₂ capture rates.

But CCS application to gas power systems faces several key challenges:

- **Geographic limits:** CCS requires dedicated CO₂ storage sites, and CO₂ storage natural resources are limited geographically and heterogeneously distributed.
- **Infrastructure limits:** The geographic limits of carbon storage can be resolved through CO₂ pipeline networks. However, many existing plants are not near pipelines, and many of the existing pipelines are at full capacity.
- **Financing:** Even if all the technical limits are overcome, financing CCS projects in the power sector is difficult and will require supportive policy. Since CCS does not create new generation (it reduces emissions and actually reduces the amount of electricity that is produced per unit of fuel burned), conventional power project financing does not support CCS retrofits, given the cost is estimated at an additional \$400/kW for a retrofit or \$25/mWh³². Innovative financing methods will have to be deployed.

Recent policy changes enable CCS deployment in the US, including the 45Q tax credit, which provides a substantial incentive for CCS application, and emerging state-based clean energy standards, which theoretically allow for CCS financing through rate recovery mechanisms. The 45Q tax credit was extended by two years until the end of 2025 in the Energy Act of 2020,



passed in December as part of the omnibus stimulus and spending bill.³³

Since natural gas power plants have low CO₂ concentrations in their flue-gas (3–7 percent) and high fuel energy content, they are disadvantaged by policies that pay by the ton and advantaged by policies that pay by the megawatt-hour. The value of the 45Q credit is calculated on a per ton basis for CO₂ that is sequestered.

Enhancements to the current 45Q tax credit would therefore be necessary to support financeable natural gas CCS projects. According to a recent Center on Global Energy Policy paper, the all-in total credit value would need to be between \$60 and \$110 per metric ton of CO₂ captured.³⁴ A bill introduced in the Senate on March 25, 2021, would provide exactly such support. The Carbon Capture Utilization and Storage Tax Credit Amendments Act would extend the 45Q tax credit by another five years to 2030 and, for direct air capture facilities that capture and securely store CO₂ in saline geologic formations, increase the 45Q credit value from \$50 to \$120 per metric ton for geological storage. The credit value would increase from \$35 to \$75 per metric ton for enhanced oil recovery (EOR) or for utilization as fuels, chemicals, and useful products.³⁵

A recent Great Plains Institute (GPI) study³⁶ offered an even lower threshold for about 3 percent of the US natural gas-fired capacity. The GPI study identified 60 facilities that qualify for near- and medium-term capture targets for up to 70 million tons of CO₂ per year at an average cost of \$57/ton. That would reduce total CO₂ emissions from the natural gas-fired fleet by 12 percent, without significant retrofits. In addition, the study identified 20 gas processing facilities that could capture 4.5 million tons of CO₂ per year in the near and medium term at an average cost of \$14/ton.³⁷

The expansion of CCS would also not require a significant level of investment in new pipeline infrastructure in comparison to what the US currently spends. To transport and sequester all the CO₂ in the GPI near-term scenario would require a build-out of 29,700 miles of CO₂ pipelines with an investment of \$16.3 billion for all sectors it identified. This is not cost prohibitive when compared to the \$30.5 billion the US natural gas industry spent on transmission and distribution investment in 2019 alone (discussed in section 2).

In the Princeton Net-Zero America study, CCUS is deployed at large scale in all scenarios except RE+ with sequestration rates of 1 to 1.7 billion tons of CO₂ per year (over 2.4 times the volume of current US oil production) servicing more than 1000 capture facilities across the nation by 2050, with the majority of geological sequestration on the Texas Gulf coast. This study requires 69,000 miles of new CO₂ pipelines at a cost of \$170 to \$230 billion. The study also has unit costs for CO₂ transport and storage falling to \$17–23/ton by 2050.³⁸



SECTION 2. OVERVIEW OF THE US NATURAL GAS PIPELINE NETWORK

The continental US has three major energy dedicated distribution systems: the electric grid, the liquid petroleum product pipeline system, and the natural gas pipeline network. Existing US natural gas pipeline infrastructure may be able to support and accelerate the transition to a zero-carbon energy sector, and the country's renewed commitment to the Paris Agreement and decarbonizing its economy lend added reason to consider this possibility.

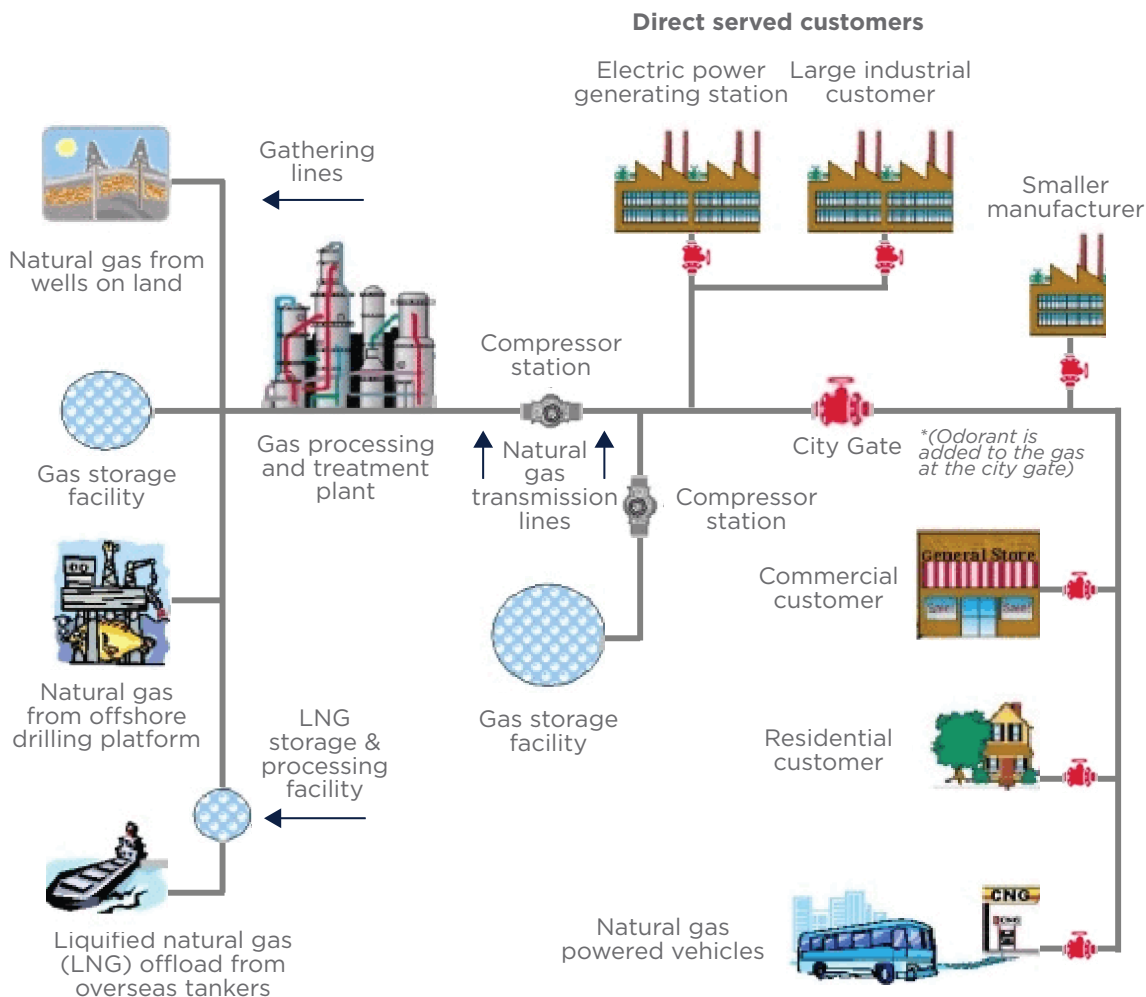
Assessing the potential future use of the pipeline network for both natural gas and zero-carbon gaseous fuels requires examining current factors such as the system's existing capacity, the level of investment to date, cost trends, price trends, and customer trends. (These factors also highlight why strong policies will be required to drive market choices toward low-carbon alternatives.)

Existing Network Capacity

At present, the United States' domestic gas pipeline network includes around 2.5 million miles of pipeline infrastructure, making it almost 6.5 times longer than the country's interstate highway system.³⁹ The network includes around 300,000 miles of transmission pipelines, which move natural gas between various processing facilities and storage facilities. It also includes 17,500 miles of gathering lines,⁴⁰ which transport gas from a production facility such as a wellhead to a transmission line. Further, the system includes 2.2 million miles of distribution mains, of which 923,000 miles are service lines to customers.⁴¹ See figure 6. The majority of the pipeline system is buried underground and thus largely protected from weather.



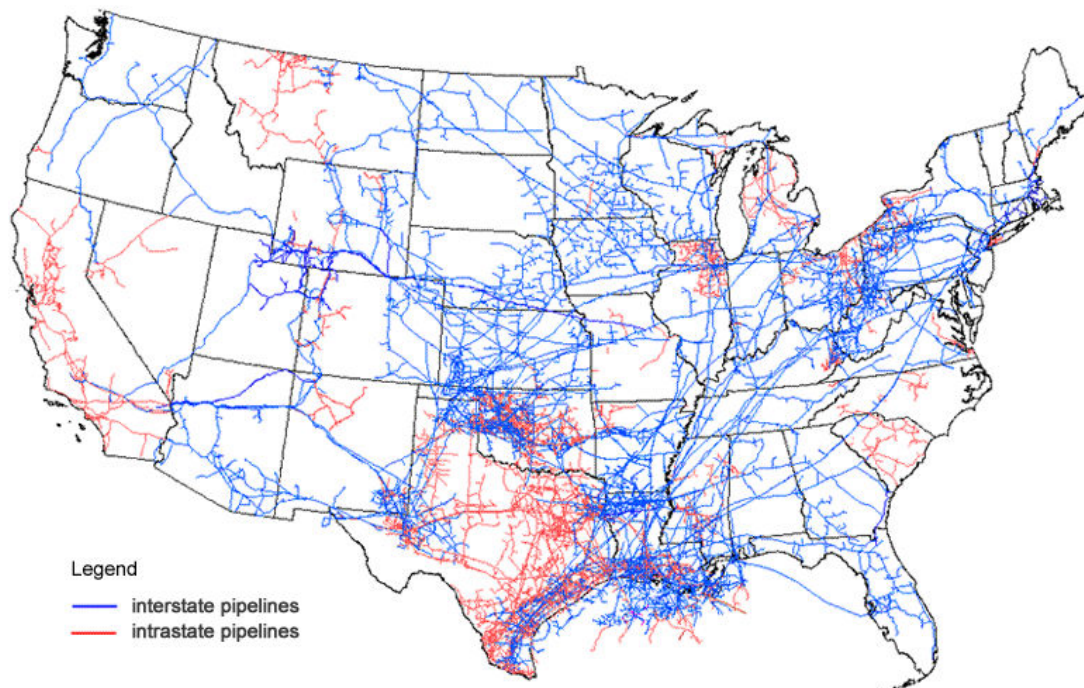
Figure 6: Natural gas pipeline system



Source: PMHSA, <https://www.phmsa.dot.gov/data-and-statistics/pipeline/natural-gas-pipeline-systems-wellhead-consumer>⁴²

The transmission network spans the entire continental United States and is also connected to Canada and Mexico (figure 7). Existing pipelines currently transport natural gas molecules around the United States to approximately 70 million households, 5.5 million commercial customers, 182,000 factories and manufacturing facilities, and 1,800 power plants.⁴³



Figure 7: Map of U.S. interstate and intrastate natural gas transmission pipelines as of 2020

Source: US EIA, *Natural gas explained: Natural gas pipelines*, <https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php>

Because natural gas consumption varies significantly by season, the US has 4.2 TCF of underground storage across 385 active facilities⁴⁴ consisting of depleted reservoirs in oil and/or natural gas fields, aquifers, and salt cavern formations. It is designed to store molecules off-peak (summer) for delivery on-peak (winter)—providing eight weeks of storage capacity at present. This complex and resilient system integrates above and below ground storage and provides high deliverability to end users.⁴⁵ This allows the pipeline system to meet peak demand during the winter heating season, which can exceed 110 Bcf/d (versus 70 Bcf/d during the off peak),⁴⁶ and the pipeline system is sized for this peak demand. Hydrogen has been proven to be able to be stored safely in salt cavern formations and is currently being tested on depleted oil and gas fields.⁴⁷

The gas network can deliver large capacity to meet variable demand—on a peak demand day, the natural gas network delivers up to four times as much energy as the electric network on a peak day.⁴⁸ At times during recent winters, natural gas has surpassed petroleum to become the most-consumed primary fuel in the United States on an energy content basis.⁴⁹ The sheer size of the natural gas peak is a challenge for full electrification, especially for heating in buildings, and will continue to result in a wide differential between peak and off-peak natural gas demand. The net impact on electric load as a result of the electrification of heating is an



important topic of ongoing research but beyond the scope of this paper.

In addition to this interseasonal storage and delivery capacity, this system is engineered to provide deliverability to customers through physical assets and commercial arrangements. These design aspects and commercial frameworks have been enabled by a federal regulatory framework, set by FERC, that provided for open access transmission networks, secondary capacity markets, and market-based rates for underground storage, to name a few key enabling aspects.

Investment to Date

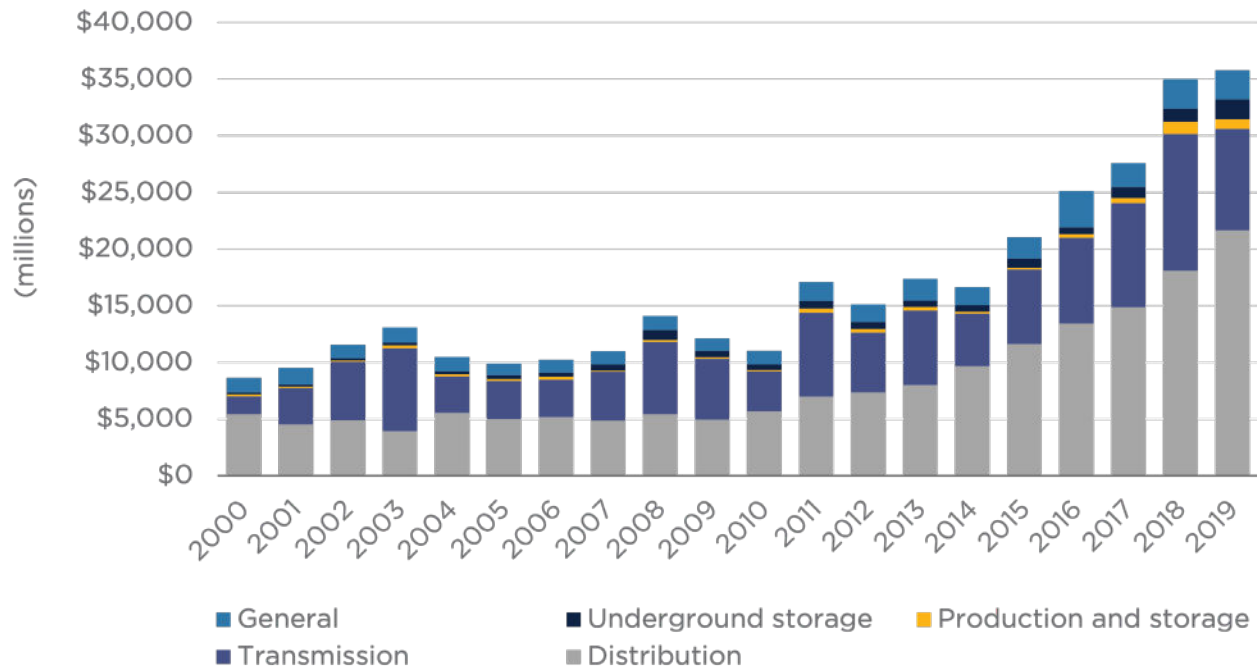
About half of the existing natural gas transmission network and a large portion of the local distribution network were installed in the 1950s and 1960s during the period when consumer demand more than doubled after World War II. But strong investment has continued beyond that period. Since 1972, more than half a trillion dollars has been invested in US natural gas pipeline infrastructure across the country.⁵⁰ In the last decade alone, over \$200 billion was invested,⁵¹ and 170,000 miles of new transmission pipelines were constructed⁵² to meet rapid growth in US natural gas production and corresponding rising demand for cheap natural gas, both for domestic use and for export as LNG.

For example, in 2019, over 46 transmission pipeline projects with 16 Bcf/d of capacity entered the system to provide additional takeaway capacity out of shale basins, with the majority from the Permian basin.⁵³ This investment brought the total transmission capacity added in the US since 2000 to approximately 273 Bcf/d.⁵⁴ The EIA database currently lists another 129 transmission pipeline projects under development in the United States⁵⁵ with a total capacity of 90 Bcf/d.

While political and public opposition to natural gas pipelines has increased, overall spending on natural gas infrastructure has not declined in recent years—largely because investment is being driven by the continued growth in the number of end users. While much of the regulation and backlash has been focused on large interstate transmission pipeline projects, leading to the cancellation of the Atlantic Coast, Constitution, and Access Northeast pipelines, for example, distribution has accounted for the largest share of gas infrastructure investment (over 60 percent of the total in 2019) as shown in figure 8.



Figure 8: Construction expenditures by type of facility



Source: AGA 2020, <https://www.aga.org/contentassets/5d9888f793ad4508bb35cb6b5f2c1865/table12-1.pdf>

This investment in distribution infrastructure has been driven by three key areas:

1. Mandated expenses such as replacement of leak prone pipes and pipeline integrity programs
2. Reliability expenses such as remote-control valves and equipment upgrades
3. New customer connections

With regard to new customer connections, it is noteworthy that even in California, where cities are banning new residential natural gas hookups,⁵⁶ the overall customer base has continued to increase, with SoCalGas adding about 34,000 new customers in 2019.⁵⁷

Cost Trends

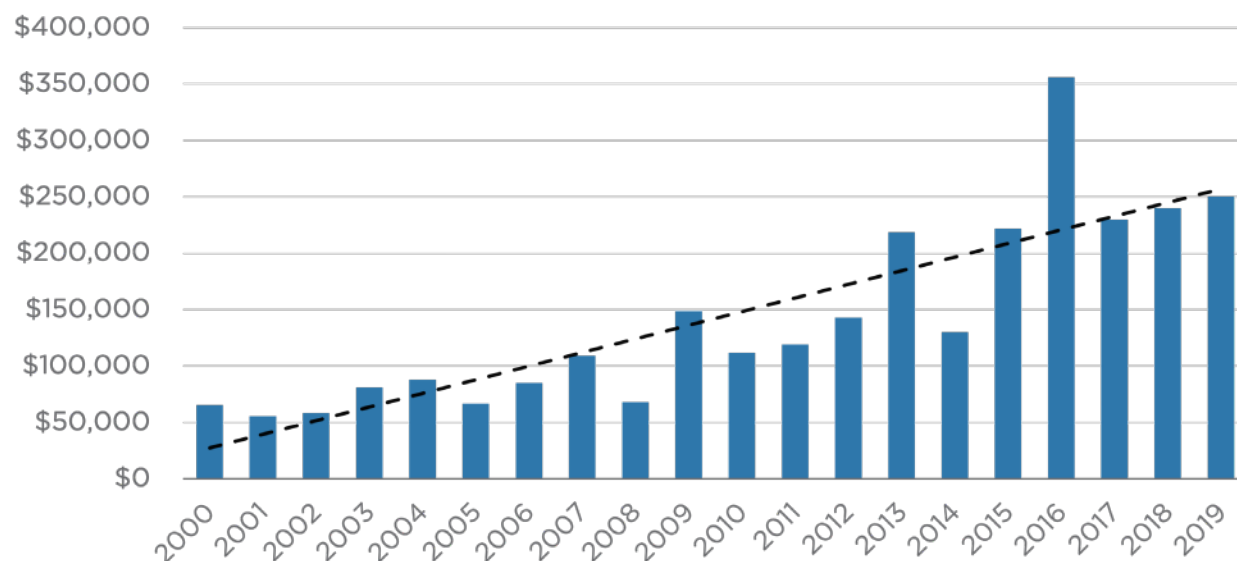
The cost of an individual pipeline project can vary widely depending on the project's size and location. For example, a project in New England will generally cost more than three times the cost of an equivalent project in Pennsylvania due to higher population density and more strict regulatory requirements.

The diameter of the pipeline is also a significant factor in the project cost (i.e., a 48-inch diameter pipeline is significantly more expensive than a 6-inch diameter pipeline given the



additional steel required). Therefore, to get an average cost per mile of pipeline, the costs are typically calculated per inch diameter first.

Figure 9: Pipeline cost per inch-mile



Note: Dotted line shows trendline of average costs.

Source: AINGAA, <https://www.ingaa.org/Foundation/FDNreports/Midstream2035.aspx>

The average real cost of a pipeline per inch mile has increased nearly 400 percent (6.9 percent compound annual growth rate) in the US over the last two decades compared to general inflation of 48 percent (2.0 percent CAGR) during that same period. For a 30-inch diameter transmission line, the inflation adjusted cost per mile was \$1.97 million in 2000 and \$7.5 million in 2019, as a result of increased legal challenges to federal permits by environmental groups and state level permitting delays.⁵⁸ In 2016, the significant jump in costs was the result of higher cost Northeast pipeline projects (due to population density and increased regulatory scrutiny) that were developed to deliver gas from the Marcellus and Utica basins.

However, the quadrupling of costs has been offset by other factors such as increased revenue from the sheer volume of gas that is now being transported, which is approximately 34 TCF (or 35 quadrillion Btu) a year.⁵⁹ Even the \$30.5 billion spent on transmission pipeline and distribution line infrastructure in 2019 equates to less than \$1 per one million British thermal units (MMBtu). As a result, transportation charges have remained about the same over that 20-year period at approximately \$1.73/MMBtu, or 16 percent of the total cost of delivered gas.

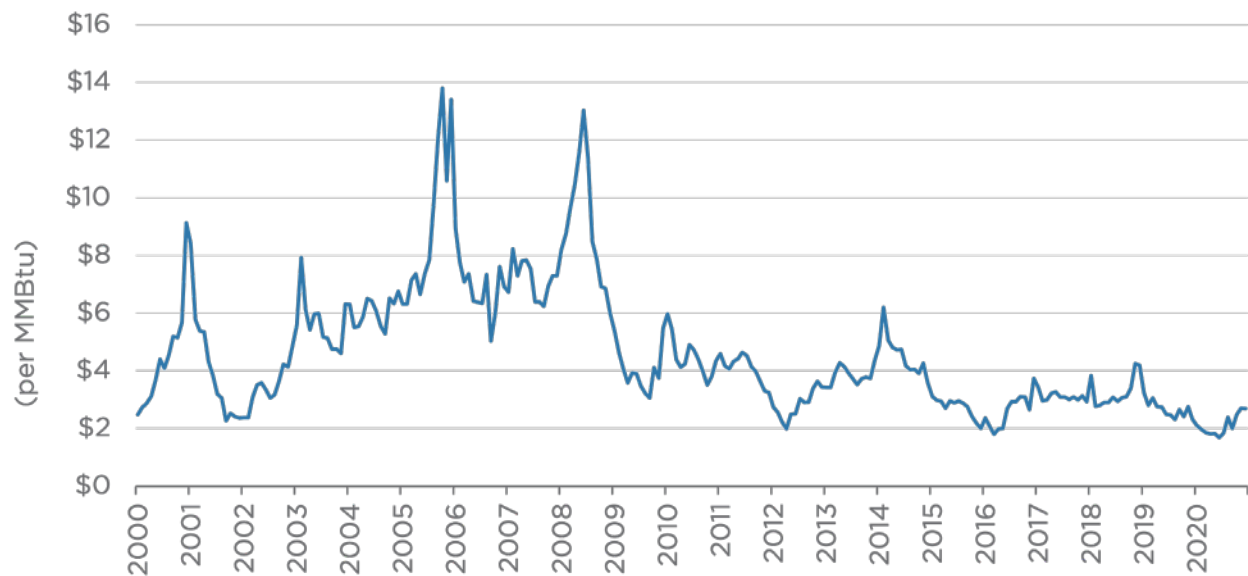


Price Trends for Natural Gas

The commodity price of natural gas has declined significantly as a result of the boom in shale gas and associated gas production. It is almost inconceivable to think that Henry Hub exceeded \$19/MMBtu in 2005, given current winter prices are below \$3/MMBtu. The fall in natural gas prices has driven the surge in demand for US natural gas across the US economy, and in recent years from overseas.

Over the last decade, US natural gas demand has risen by 22 Bcf/d (35 percent).⁶⁰ In 2019, natural gas provided 35 percent of all energy consumed in the United States.⁶¹

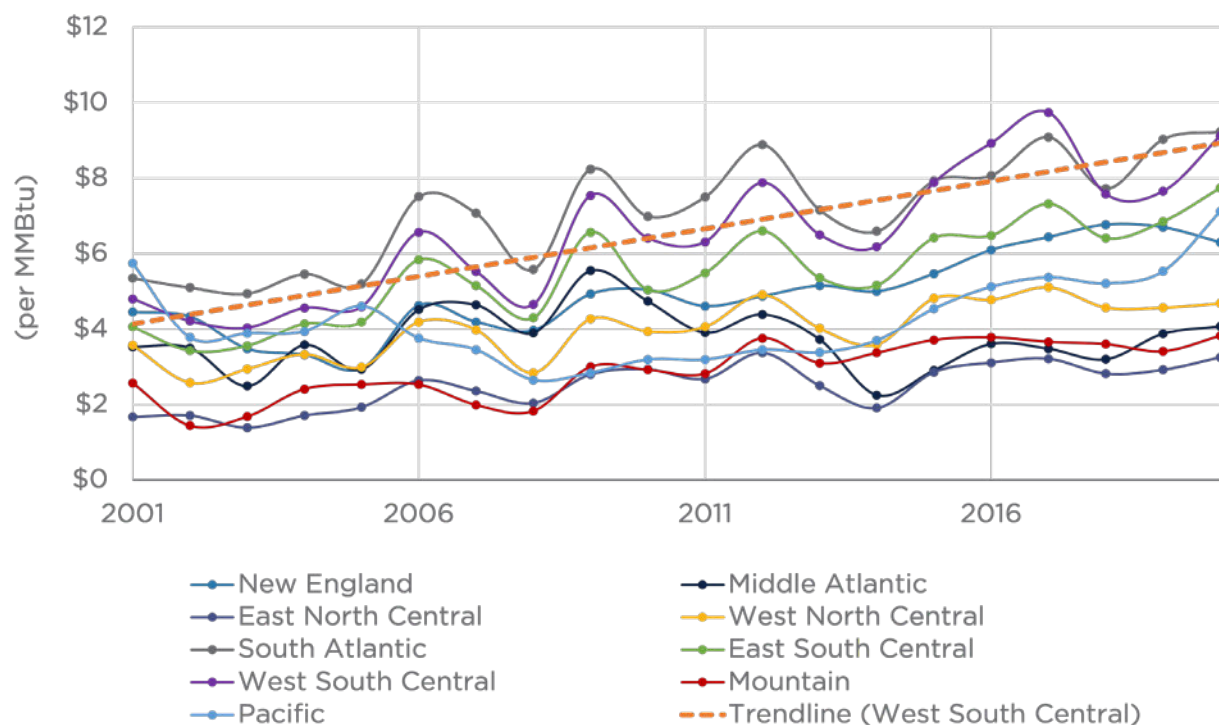
Figure 10: Henry Hub natural gas prices



Source: US EIA Short-Term Energy Outlook Data Browser, <https://www.eia.gov/outlooks/steo/data/browser/#/?v=i6&f=A&s=&start=2000&end=2021&id=&maptype=0&ctype=linechart&linechart>

While the commodity price of natural gas has declined and transportation charges have remained steady, the distribution cost of natural gas—the fee that a local gas utility (also called a local distribution company [LDC]) charges to deliver gas to customers—has risen steadily over the year. As a result, the spread between wholesale and retail costs has risen across the US even as the commodity cost of natural gas has fallen. For example, the spread in the Southwest-Central region (Texas, Oklahoma, Arkansas, Louisiana)⁶² has risen from an average of \$4 to \$9 since 2000, as shown in figure 11.



Figure 11: Price spread between wholesale and retail prices across US regions

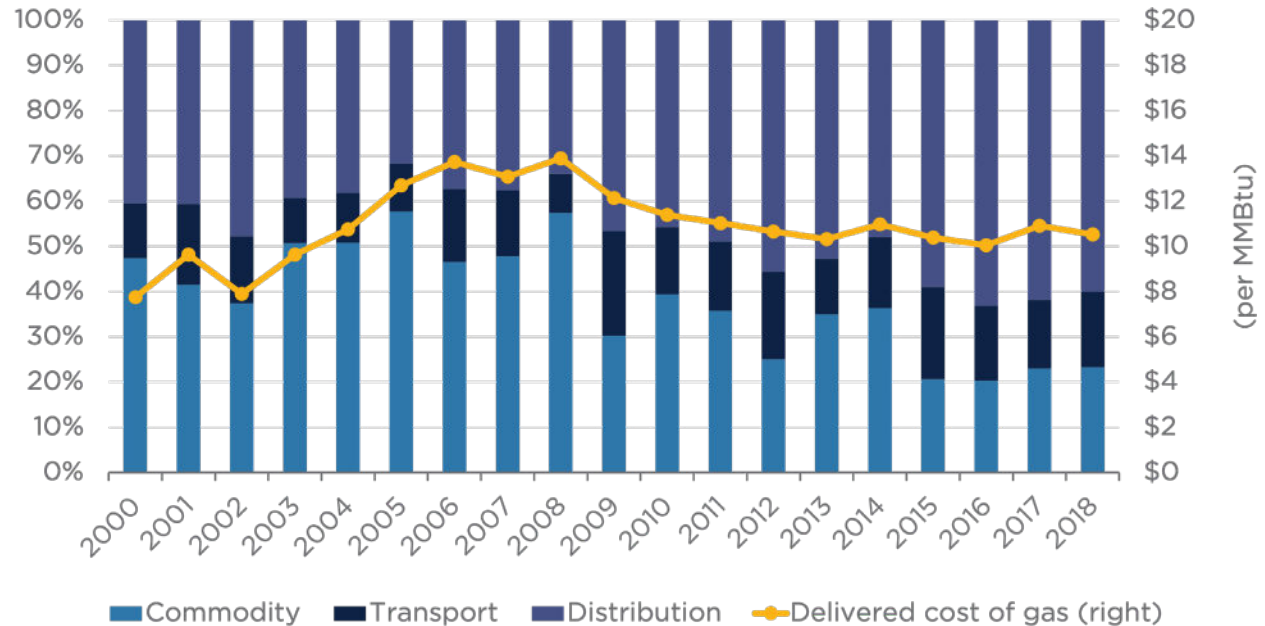
Source: US EIA 2020; IEA 2020; BP 2020, <https://www.eia.gov/outlooks/steo/data/browser/#/?v=16&f=A&s=&start=2000&end=2021&id=&motype=0&ctype=linechart&linechart=NGHMC>

For these reasons, residential users have not seen a reduction in prices from the decline in underlying commodity price, but rather it has made it easier for gas utilities to pass on the costs of upgrades and expansions to their systems without customers seeing an increase in the delivered price of gas. The delivered cost of natural gas has remained relatively steady over the last decade at \$10–11/MMBtu.

As commodity prices have fallen, distribution charges now make up 60 percent of a customer's delivered cost of gas (figure 12). The sheer volume of natural gas that flows through our system in addition to the lower cost of the commodity indicates that utilities could accelerate the replacement of older and leakier distribution lines without having to markedly increase the costs to their customers.



Figure 12: Expense share and delivered cost of natural gas

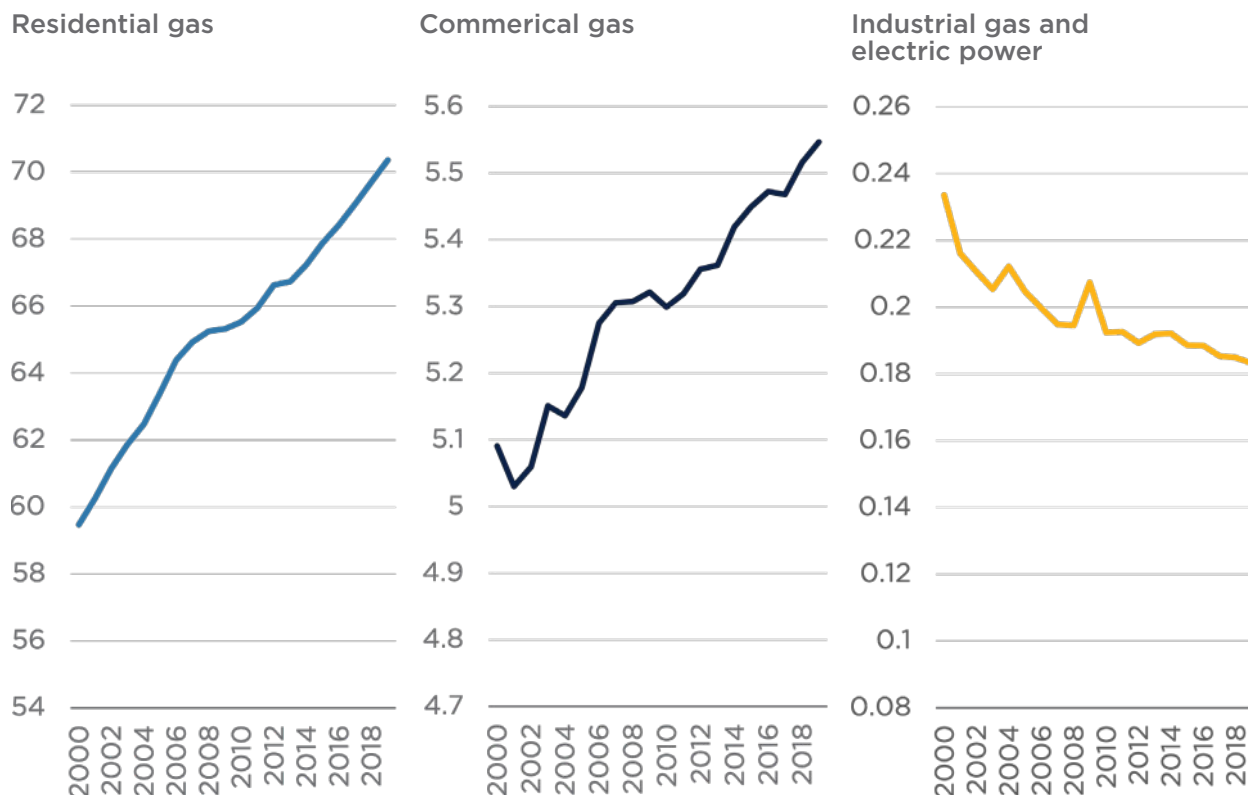


Source: US EIA, <https://www.eia.gov/energyexplained/natural-gas/prices.php>; Wellhead data post-2012 from S&P Platts (using average of regional production)

Customer Trends

The total number of gas users has increased steadily by 11.4 million since 2000, with nearly 11 million coming from new residential end users. Commercial users have increased by 425,000 while industrial users have actually declined by 48,700 as a result of industrial plants moving overseas for manufacturing.⁶³ Since 2010, natural gas utilities have added over half a million customers each year,⁶⁴ as shown in figure 13, suggesting that the limited number of municipalities banning natural gas use in new buildings is not indicative of a broader trend across the rest of the US.⁶⁵ Noted here is that power plants are included in the industrial category in this figure. While there has been a large number of new gas-fired power plants in recent years, they still represent a small portion of the industrial customer base. Overall, the US has a total of 1,800 natural gas-fired power plants out of 183,200 industrial users.



Figure 13: Natural gas end users (millions)


Source: AGA 2020, <https://www.aga.org/research/data/end-users/>

These trends suggest that a rapid transition to zero-carbon supplies will likely require strong policy changes to drive market choices to low-carbon alternatives (e.g., low- or zero-carbon hydrogen or electric heating). This finding and its implications are discussed in further detail in section 4 of this report.



SECTION 3: POTENTIAL FUTURE USES OF THE US PIPELINE NETWORK FOR ZERO-CARBON ENERGY SOURCES

The expansive nature of the current natural gas grid can support the delivery of low- and zero-carbon fuels (e.g., hydrogen, biogas, and synthetic methane) to all sectors of the economy through existing infrastructure, including those sectors that are broadly considered “hard to abate” (for which electrification is not currently a viable pathway to zero emissions), such as with industrial processes like cement and steel production, the fertilizer industry, and heavy-duty transport. In many cases, existing pipeline infrastructure would need to be retrofitted in order to support increasing levels of zero-carbon fuels.

Hydrogen

Hydrogen is increasingly viewed as a natural complement, partner, or substitute to natural gas. Like natural gas, hydrogen combustion provides high-quality heat on demand. However, the combustion of hydrogen produces no greenhouse gases, though hydrogen can produce high levels of NO_x at high flame temperatures, unless specifically low NO_x technology is employed.⁶⁶ As such, hydrogen has near-term relevance if it can be produced without greenhouse gas emissions and at a reasonable cost. Three primary pathways exist today for making hydrogen:

1. Gray hydrogen is made via coal gasification or steam-methane reforming, a production process in which high-temperature steam is used to produce hydrogen most typically from natural gas. Gray hydrogen creates intensive CO₂ emissions. One potentially abundant, cost-competitive source of gray hydrogen undergoing further research involves sour gas.⁶⁷
2. Blue hydrogen is produced from fossil fuels with the process of CCS. It's only difference from gray hydrogen is that the CO₂ emitted during the production of blue hydrogen is sequestered via CCS. Large-scale production of blue hydrogen makes it possible to reduce CO₂ emissions for wide-reaching hydrogen applications today by simply retrofitting gray hydrogen facilities with CCS. There are eight facilities operating globally today that make blue hydrogen at scale.⁶⁸
3. Green hydrogen (including renewable hydrogen) is produced by electrolysis of water using zero-carbon electricity sources such as solar, hydro, nuclear, and wind. The hydrogen is produced by splitting water (H₂O) into hydrogen (H₂) and oxygen (O₂), and this makes hydrogen that is effectively carbon free. If grid electricity is used, the emissions would be substantial, so zero-carbon electricity is required. Gasification of biomass is another pathway to making renewable hydrogen. There are currently no facilities that make green hydrogen at scale today, though there are two demonstration projects in operation.⁶⁹

Ten million metric tons of hydrogen are currently produced in the United States every year



(95 percent of which is gray hydrogen from steam methane reforming of natural gas). That is equal to 3,842 Bcf of hydrogen or 10.5 Bcf/d. The primary uses of hydrogen today are in the oil refining and ammonia industries.⁷⁰

To achieve cost parity with natural gas, hydrogen must be produced at roughly \$0.3 per kilogram. In the US, gray hydrogen production costs from \$3.50/MMBtu gas are between \$1.0 and \$1.5 per kilogram. Today, blue hydrogen can be produced at \$1.40–\$2.10/kg at 60-90 percent CO₂ capture rates while green hydrogen costs between \$4.50 and \$8.50/kg to produce from zero-carbon electricity. The carbon footprint and unsubsidized costs of hydrogen are presented in figure 14.

Currently, blue hydrogen is up to 80 percent more expensive than gray hydrogen, and green hydrogen is up to 600 percent more expensive than gray hydrogen.

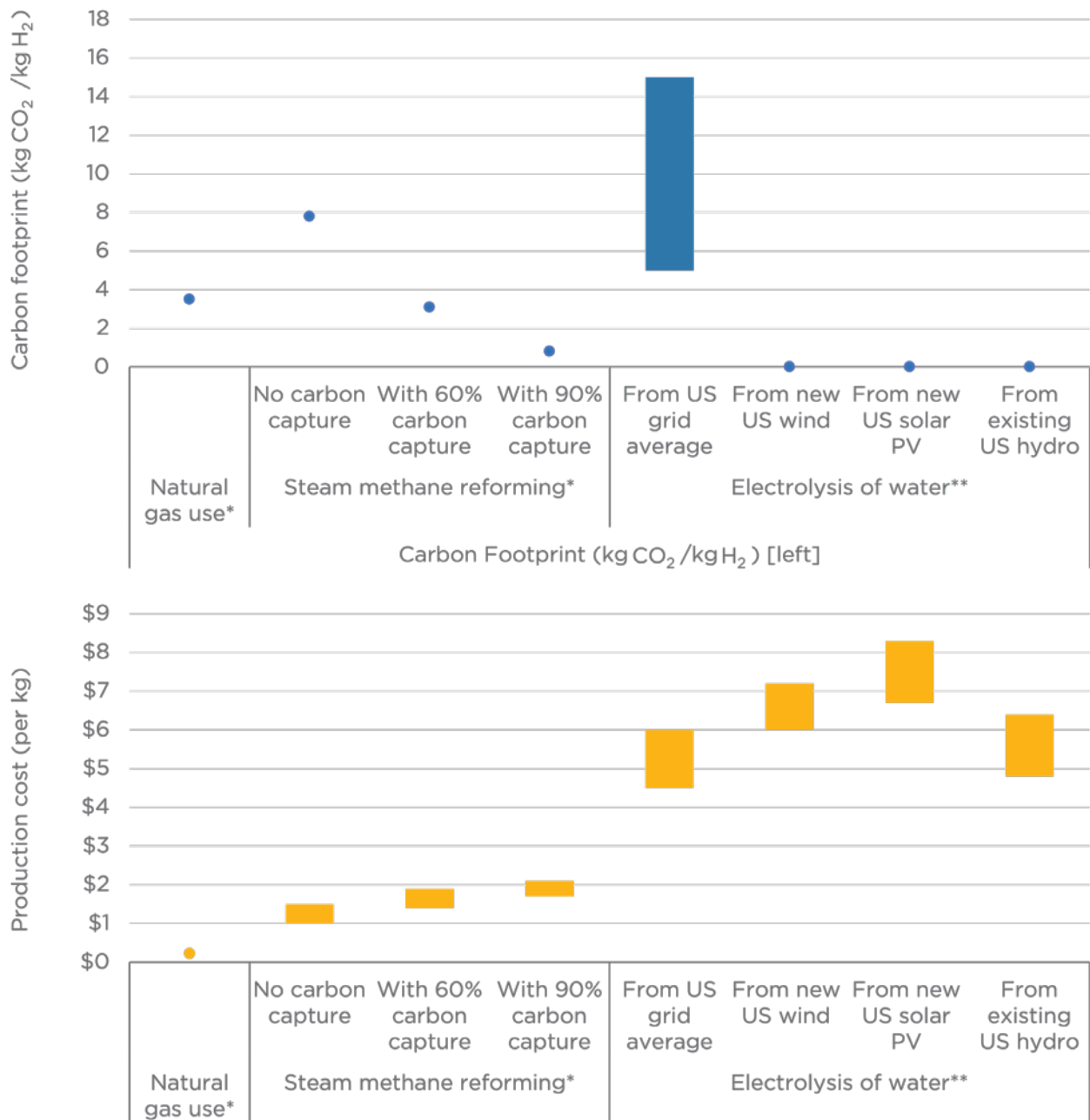
At \$1,000/kW electrolyzer costs are very high up the cost curve, but those costs are coming down at a rate of about 20 percent per year.⁷¹ However, even if electrolyzer costs drop 50 percent, the cost of green hydrogen only falls by 15 percent. In other words, the main factor in the cost of green hydrogen is the cost of the power used to produce it.

Excess renewable power generation from wind and solar farms can be sent to an electrolyzer to produce green hydrogen. However, there is substantial competition for these excess electrons, and they would typically have low-capacity factors, leading to high costs to produce green hydrogen.⁷² Power purchase agreements for solar power may be as low as \$0.025/kWh, but those are often at a 25 percent capacity factor. Much higher capacity factors are needed to produce green hydrogen affordably. The main cost reduction will have to come from very inexpensive and very plentiful renewable energy. Expanding and extending existing investment and production tax credits for solar and wind would help facilitate the production of green hydrogen.

Although many anticipate rapid reduction in the costs of green hydrogen due to declines in both zero-carbon power and electrolyzer costs, these approaches will not compete broadly with gray or blue hydrogen until after 2030.⁷³



Figure 14: Carbon footprint and production costs for hydrogen



Note: *Assumes \$3.50/MMBtu natural gas; **assumes \$1,000/kw electrolyzer costs

Source: J. Friedmann et al, "Low-Carbon Heat Solutions for Heavy Industry: Sources, Options, and Costs Today", Center on Global Energy Policy, October 2019, <https://energypolicy.columbia.edu/research/report/low-carbon-heat-solutions-heavy-industry-sources-options-and-costs-today>



In the scenarios presented in the Princeton Net-Zero America study, hydrogen systems begin expanding substantially starting in the mid-2030s, reaching total hydrogen volumes in 2050 of 60 million tons or six times hydrogen production in the US today, which is well below what would be needed to move the US to a fully hydrogen-based economy but still could meet 14 percent of total US energy demand.⁷⁴

The Fuel Cell and Hydrogen Energy Association has a similar ambitious scenario of zero-carbon hydrogen production reaching 63 million tons by 2050, leading to a reduction of US greenhouse gas (GHG) emissions of 16 percent and NO_x emissions of 36 percent.⁷⁵

For these and other related reasons, the extent to which the US is able to ramp up hydrogen production through 2040 will depend on whether policies are in place to support it. Such policies were outlined in the comprehensive climate plan released by the House Select Committee on the Climate Crisis on June 30, 2020,⁷⁶ and include:

- Increased Congressional funding for the Department of Energy (DOE) to strengthen and expand hydrogen research.
- Congressional tax incentives for industrial hydrogen use and low emission hydrogen production (e.g., a technology-neutral production tax credit for low emission hydrogen based on emissions displaced). Of note here is that a production tax credit of \$0.70/kg for blue hydrogen and \$1.00-1.50/kg for green hydrogen would be enough to encourage commercial uptake and bring online more projects.⁷⁷
- An investment tax credit for industrial hydrogen end uses, such as equipment upgrades at facilities that switch from emissions-intensive heating or processes to using hydrogen.

Another way the US government could help establish a hydrogen market is through green procurement. The US Department of Defense purchases 4 percent of all the fuels in the United States and could start purchasing zero-carbon hydrogen fuels in addition to steels and chemicals produced with zero-carbon hydrogen.

The oil and gas industries could help spur hydrogen production as part of a long-term diversification strategy and a way to enhance their social license to operate. In a 2020 survey of more than 1,000 senior oil and gas professionals, one in five (21 percent) said their organization was already actively entering the hydrogen market, and 42 percent said that their organization intended to invest in hydrogen in 2020 (compared to only 20 percent in 2019).⁷⁸

In 2019, the Trump Administration launched H2@Scale,⁷⁹ a program to explore the potential for wide-scale hydrogen production and utilization in the United States. The program is led by the National Renewable Energy Laboratory with \$100 million over five years. On July 20, 2020, the DOE announced approximately \$64 million in fiscal year 2020 funding for 18 projects that will support the H2@Scale vision for affordable hydrogen production, storage, distribution, and use.

In October 2020, DOE's Office of Energy Efficiency and Renewable Energy and the Dutch Ministry of Economic Affairs and Climate Policy's Directorate General for Climate and Energy



issued a statement of intent for collaboration. Through the effort, real-world data from hydrogen applications will be gathered to guide both organizations' future hydrogen research and development demonstration activities.⁸⁰

These projects and the focus by the DOE on broader adoption of hydrogen outside just hydrogen cells for transportation are a good launching point for advanced hydrogen technology development, but they will not be enough to establish a hydrogen economy in the US. The US needs to adopt an approach similar to the EU, which has planned to spend 820 billion euros by 2050 on hydrogen production capacity and deployment.⁸¹ President Biden has named renewable hydrogen as an innovation priority in his Climate Change Plan.⁸² Beyond funding for technology, a significant public education and communication plan will likely be needed to assuage some perceptions of danger related to hydrogen's flammability and other attributes.

Technical Considerations for Moving Hydrogen Using Natural Gas Pipeline Networks

In parts of the economy where electrification cannot be a substitute for natural gas, such as steelmaking and other heat-intensive industrial processes, hydrogen can play a key role. But it will take considerable time and investment to get to that point, even if just utilizing the existing natural gas pipeline system.

The most cost-effective way to transport hydrogen is via pipeline. Only limited quantities of hydrogen can be transported via truck or rail, and as hydrogen has a relatively low volumetric energy density, its transportation, storage, and final delivery to the point of use comprise a significant cost and make rail or truck uneconomic compared to a pipeline, which allows for significantly larger volumes to be transported.⁸³ There are currently 1,600 miles of hydrogen pipelines in the US (compared to the 2.5 million miles of natural gas pipelines or 0.064 percent of the gas network). These pipelines are primarily located in the Gulf Coast region where large hydrogen refineries and chemical plants are concentrated.⁸⁴

The potential introduction of hydrogen into the existing natural gas pipeline network is currently limited by technical concerns, which vary with pipeline condition and role (e.g., transmission vs. distribution), composition, pressure, and setting. These concerns include leakage, safety, and function. Although hydrogen can be blended to a certain degree into existing natural gas systems with minimal risk, moving to larger fractions (i.e., greater than 20 percent) brings significant challenges. But solutions to those challenges are now being studied to identify how to increase this blending ratio while still utilizing the existing network.⁸⁵

Pipeline Materials

Approximately 96 percent of onshore and offshore US natural gas transmission pipelines are steel.⁸⁶ Transmission lines rarely have leakage issues because, given the volume and pressure of gas flowing through them, leaks are both too costly and dangerous not to repair. The major concern with moving hydrogen through existing transmission lines would be the effect of hydrogen embrittlement (where hydrogen makes the metal start to crack and fracture) over time. High-strength steels, which are designed to be able to withstand more stress (measured in kilo-pound per square inch, or ksi), are more susceptible to hydrogen embrittlement, so the use of thicker, low strength steels—such as lower carbon grade or stainless-steel welded pipe—is



recommended for hydrogen pipelines.⁸⁷

While cast-iron pipelines (still found in the northeastern US) are completely incompatible with hydrogen, plastic pipelines do not face the embrittlement issues that steel pipelines do with hydrogen. Hydrogen was thought to leak from plastic pipelines more readily than natural gas through permeation, but recent research has shown those leak rates are similar to natural gas.⁸⁸ An application of a copper-based epoxy to thinly coat the pipe has been shown to successfully contain all gas blends, and threaded pipe fittings prevent hydrogen leaks.⁸⁹

Polyethylene (PE)—the most common plastic in use today—pipes have been shown to be compatible with hydrogen and are being used to convert the natural gas network in Leeds, England, to 100 percent hydrogen by 2028–2035.⁹⁰ One study calculated that the yearly loss of hydrogen by leakage through PE pipelines amount to approximately 0.0005–0.001 percent of the total transported volume. Other studies have shown that high density polyethylene is compatible with high percentages of hydrogen.⁹¹

Other potential solutions include using composite (fiberglass reinforced plastic [FRP]) pipelines for hydrogen distribution. The installation costs for FRP pipelines are about 20 percent less than that of steel pipelines because the FRP can be obtained in sections that are much longer than steel (up to 0.5 mile), minimizing welding requirements.⁹² As more data comes out about which types of plastic pipelines are best suited to hydrogen transport, utilities could be encouraged to use those pipes in their mains replacement programs.

Because the costs of constructing a large scale, dedicated hydrogen pipeline system would be significant, and completion of a countrywide network could take decades (and face many of the permitting issues that natural gas pipelines face today), finding ways to use the existing natural gas system could accelerate wider adoption of hydrogen.

A number of pilot projects are testing how hydrogen interacts with existing pipeline materials, and in the US concentrations of up to 5 percent hydrogen (95 percent natural gas) have been tested successfully so far.⁹³ Current tests are also looking at what concentrations can be used in regular steel pipelines without causing embrittlement issues.

Relatively low concentrations of hydrogen (5–20 percent by volume) appear to be feasible with very few modifications to existing pipeline systems or end-use appliances.⁹⁴ (End-use requirements are generally the most restrictive conditions on increasing hydrogen blend levels in natural gas. Current end devices [e.g., engines, industrial burners, turbines, and residential and commercial appliances] are optimized for use with pure natural gas. Altering the composition of the gas supply could result in changes such as heating value, flame stability, blow off limits, and flashback.⁹⁵ A number of studies are being done, both in the US and Europe, to test for compatibility of hydrogen blends with appliances.⁹⁶) As hydrogen concentrations increase, alterations will be required to existing pipelines such as replacement of older and high strength steel pipelines, precoating lower strength steel pipelines, adding new compressor stations, and pressure managing equipment that could result in hydrogen volumes significantly above that 20 percent threshold without compromising the safety or integrity of the pipeline system.⁹⁷

But not all of the US pipeline system has to be made hydrogen-ready at once. While the system



is extensive, it also has the ability to be isolated so that testing hydrogen compatibility can be gradual. For example, specific use cases (e.g., for a specific utility plant or industrial area or a closed loop residential area) can be tested as pilot projects, and a number of US utilities have begun to do so.⁹⁸ Furthermore, many industrial users may choose to produce hydrogen on-site, as happens today⁹⁹ or could initially focus their efforts on regional locations like the Gulf Coast.

A staged approach where hydrogen blending is isolated to certain areas can be helpful for policymakers by allowing them to identify the most congruous sections of the system for hydrogen to first be introduced and then set policy incentives as it is better known what materials and end users are most compatible for further hydrogen expansion.

Safety Concerns

Distribution pipeline systems are generally smaller in diameter than transmission pipelines and, as mentioned, are constructed of several kinds of materials, including a significant percentage of plastic pipes. Distribution pipeline failures almost always involve leaks rather than ruptures because the internal gas pressure is much lower than for transmission lines. Hydrogen is a much smaller molecule than methane, so its leakage rate through pipe walls and joints is about a factor of three higher than for natural gas. Hydrogen is extremely flammable, making it susceptible to combustion, even in small concentrations, although leaks will disperse more quickly into the air due to its low density and high rate of molecular diffusivity. Flammability remains a significant concern for distribution pipelines in residential areas.¹⁰⁰

As most leak detection systems are set up to detect methane, those would also need to be upgraded.¹⁰¹ The dispersion behavior of hydrogen is different than other gases, given the small size of hydrogen atoms, and it is colorless, tasteless, and odorless, so that specific sensors or odorization would be required to detect it. Some proposals also include colorization of hydrogen.

The natural gas composition in a pipeline is another consideration. Hydrogen has one-third the heat value of natural gas per cubic foot, so significantly higher physical volumes of hydrogen would be needed in the pipeline system as natural gas is substituted. Because compressors operate on the basis of volume rather than energy content, considerably higher compression horsepower would be required to move comparable amounts of energy as compared to the power requirements of natural gas. It would also require a change in metering at both the city gate and residential level.

Pipeline operators are focused on reliability and safety, so the testing of increased concentrations of hydrogen in the system will be a slow and steady process. While US utilities are looking to Europe, what works in European pipeline systems may not be as readily applicable in the US. Regional variations across the US system, in terms of pipeline materials used, flow rates, and pressure, will all determine how much hydrogen can go into the system on a case-by-case basis; one size does not fit all.

There are many unknowns of hydrogen's compatibility with the US system and what concentrations can safely be added without damage to our existing infrastructure or increased risk of combustion. While the US Department of Energy has historically focused



hydrogen research investment on fuel cells, recent Cooperative Research and Development Agreements calls show that the DOE is taking a more holistic approach to hydrogen development to spur development across sectors.¹⁰² Combined with the R&D being undertaken in Europe, Australia, and Japan, as well as the increased interest in oil and gas companies to invest in hydrogen, many of those unknowns could become knowns in the next five years.

Biomethane

Biomethane (also known as renewable natural gas) is a near-pure source of methane produced either by “upgrading” biogas or through the gasification of solid biomass followed by methanation.

Biogas

Biomass derived gaseous fuel (biogas) differs from natural gas in that it is naturally produced from the breakdown of organic waste, and thus is a renewable energy source. Biogases include a range of gas compositions but are typically 50–70 percent methane, with CO₂ making up most of the balance along with small amounts of nitrogen, oxygen, and hydrogen sulfide. Biogases with significant energy value can be produced by intentional or unintentional aerobic (with oxygen) or anaerobic (without oxygen) digestion or fermentation of biodegradable organic matter.¹⁰³

Biogas can also be upgraded into biomethane or renewable natural gas (RNG) by removing the CO₂ and other contaminants and then injecting into natural gas pipelines or used as a vehicle fuel. Biogas is upgraded to pure methane by removing water, carbon dioxide, hydrogen sulfide, and other trace elements. This upgraded biogas is comparable to conventional natural gas and thus can be injected into the pipeline grid interchangeably with natural gas or used as a transportation fuel in a compressed or liquefied form.

As most sources of biogas, such as landfill gas, livestock manure digestors, or wastewater plants, are smaller and more geographically spread out than current natural gas well sites, they need to be aggregated to a centralized system for processing in order to make economic sense. Noted here is that high CO₂ gas does not pose an issue for plastic pipelines, so no special materials are needed to bring biogas to a central processing facility.

Because biogas is considered a renewable energy source, many states offer incentives for the production of biogas or combustion of biogas, or both.¹⁰⁴ Other incentives that can promote the use of biogas include production tax credits, direct grants, and low interest financing. Biogas can be used to produce heat and electricity for use in engines, microturbines, and fuel cells. Biogas feedstocks can also be cofired with fossil fuels in power plants.

It is more costly for some biogas feedstocks to be used in the existing gas pipeline network than others. For example, biogas facilities that use feedstock predominately found in rural areas (e.g., manure and energy crops) are likely to be farther away from existing lines and therefore have higher transportation costs. In those cases, using biogas for electricity generation may be more profitable than upgrading it to biomethane and supplying it to the pipeline. The opposite



is likely to be true for wastewater plants and, to an extent, landfill gas, which are usually situated closer to existing lines.¹⁰⁵

The United States currently has 2,200 operating biogas systems across all 50 states and has the potential to add over 13,500 new systems.¹⁰⁶ The National Renewable Energy Laboratory's most recent analysis of RNG potential, published in 2014, estimated an annual potential supply of 16 million tons of methane, or over 756 billion cubic feet (Bcf) or 2 Bcf/d from biogenic feedstocks.¹⁰⁷

The key limit for biogas is supply, followed by cost. Even with greatly expanded production, biogas generation could provide only up to 3 to 5 percent of the total domestic natural gas market at a cost of \$5-6/MMBtu by 2040.¹⁰⁸ While this resource potential appears small and easy to overlook, these waste resources are underutilized and present an opportunity for greenhouse gas mitigation and production of renewable energy fuel.¹⁰⁹

In the Princeton Net-Zero America study, biogas is primarily used to make hydrogen with carbon capture. It is used in the power system when pathways to negative emissions are vital (electrification delay), renewables are constrained, and biomass supplies are high.

Biomethane from Synthetic Gas

The potential for biomethane produced from gasification rather than anaerobic digestion would significantly ramp up potential supply. Biomethane from synthetic gas is produced by using woody biomass, which is first broken down at high temperature (between 700 and 800°C) and high pressure in a low-oxygen environment. Under these conditions, the biomass is converted into a mixture of gases, mainly carbon monoxide, hydrogen, and methane (syngas). This syngas can be converted to high quality methane by methanation.¹¹⁰

The methanation process then uses a catalyst to promote a reaction between the hydrogen and carbon monoxide or CO₂ to produce methane. Any remaining CO₂ or water is removed at the end of this process.

Unlike biomethane from digestion, the production of biomethane from gasification enables a wider range of biomass fuels, such as wood to be converted into biomethane.¹¹¹ Several demonstration projects are underway for thermal gasification of woody biomass (e.g., the 20 MW GoBiGas project in Gothenburg, Sweden).¹¹²

Synthetic Methane

Synthetic methane, also known as substitute natural gas (SNG), or synthetic natural gas, is a fuel gas that can be produced from fossil fuels or using renewable electricity with power-to-gas systems. As a result, synthetic methane, like green hydrogen, is able to support electrical systems with high levels of renewable electricity by offering a long-term storage option for excess solar and wind generation. This enables renewable energy to be used to produce a quasi-fossil fuel (i.e., power to gas).

The methanation process uses CO₂, for example from biogas production, and this combined with hydrogen (H₂) from excess renewable electricity produces methane (i.e., power to methane



[PtM]), which can not only be distributed simply and cost-effectively in the natural gas network but can also be stored for longer periods of time.

The usage of SNG in the network is advantageous as it is identical to natural gas and is compliant with all network devices. Unlike hydrogen, SNG usage in the network has no restrictions, and natural gas appliances can operate on SNG. Also, a large amount of SNG can be stored in the gas network, which prevents the need for construction of additional storage facilities.

The cost estimations of synthetic methane vary significantly but remain considerably higher than biomethane or hydrogen alone: for 2030 around \$23-110/MMBtu and for 2050 around \$15-60/MMBtu.¹¹³ Different assumptions regarding the cost of renewable electricity and the load of the electrolyzer are the main reasons for this large range.¹¹⁴ PtM needs a low electricity cost, a significantly lower capital expenditure (currently up to \$1,800 per installed kW), and a high number of operational hours (above 3,000) to reach a similar price as natural gas.¹¹⁵

The processes of the PtM chain are widely developed. However, there is to date little experience with the entire PtM system, with only a handful of projects worldwide—most of them in Germany, with the largest being the 6 MW Audi e-Gas plant in Wertle.¹¹⁶ PtM might play an important role in the future energy sector, but further projects need to be developed, and costs need to come down considerably. However, if synthetic methane does progress along these lines, its similarity to natural gas would make it particularly suited for use in the current US pipeline network.



SECTION 4: RECOMMENDATIONS FOR POLICYMAKERS

As discussed in this report, analysis to date shows continued use of natural gas for at least the next three decades, as well as increasing use of low- and zero-carbon gaseous fuels. These projections lead to a key question: How can the US natural gas pipeline network better limit its current greenhouse gas emissions and be adapted to transport increasing levels of lower-carbon fuels?

Two specific policy recommendations seek to address this critical question:

1. Change regulations on methane leak detection and repair to make the existing pipeline network as low emissions as possible.
2. Expand on existing regulatory authority to allow for retrofitting the transmission and distribution system for more hydrogen usage in the pipeline network, and increase R&D funding to test the integrity of the pipeline system with greater levels of hydrogen and other zero-carbon fuels.

More discussion is given to the first recommendation than the second in this section. There is enough data available on the existing pipeline network to make extensive policy recommendations about how to make our current system as low emissions as possible. But there is still much to learn about how to make the current system compatible with increased hydrogen use and other zero-carbon fuels and what materials are best designed to do that. Specific policy proposals for the second recommendation will become clearer in the coming few years after a number of pilot projects begin operation, private-public partnerships expand research and development on increased hydrogen use, and the government directs more funding to solving this issue on an economy-wide scale.

Recommendation 1. Change Regulations on Methane Leak Detection and Repair to Make the Existing Pipeline Network as Low Emissions as Possible.

Methane leaks are the primary climate impact of pipeline infrastructure. In the transmission and distribution of natural gas, methane can be released from numerous sources, including faulty piping and valves, pneumatic controllers, and unburned methane in the exhaust of powered compressor stations.¹¹⁷ If significant progress is made in tracking and reducing system-wide methane emissions in the US, the carbon intensity of natural gas could be improved.

Distribution lines, which constitute the majority of gas infrastructure miles, are also responsible for a significant number of leaks. A study released in July 2020, estimated that methane emissions from US distribution pipelines were about five times EPA estimates with over 630,000 leaks in US distribution mains, resulting in methane emissions of 0.69 million tons/year, or 7.6 percent of US total methane emissions.¹¹⁸

Upstream methane emissions (e.g., flaring) represent another opportunity for improving the



environmental footprint of the existing natural gas pipeline system.¹¹⁹ These emissions are beyond the scope of this report.

Accelerate Pace to Replace Remaining Cast-Iron Pipelines

Approximately 97 percent of natural gas distribution pipelines in the US were made of plastic or steel at the end of 2019. The remaining 3 percent is mostly iron pipe.

Uncoated steel pipelines are known as bare steel pipelines, and while many of these pipelines have been taken out of service, some are still operating today. The age and lack of protective coating typically makes bare steel pipelines of higher risk for leaks or ruptures as compared to some other pipelines and candidates for accelerated replacement programs.¹²⁰ Despite its small percentage in the overall network, cast-iron pipe is responsible for 10 percent of all US distribution leaks.¹²¹ This means that relatively small volumes of replacement could yield substantial reductions in emissions.

The amount of cast-iron and wrought iron pipeline in use has declined significantly in recent years due to increased state and federal safety initiatives. 22 states have completely eliminated cast-iron or wrought iron natural gas distribution lines within their borders.¹²² Most of the remaining iron distribution pipelines are located in the Eastern states, and the replacement programs are slow going.

For example, in the District of Columbia, the most recent Public Service Commission decision on the Washington Gas and Light's Revised Accelerated Pipe Replacement Plan was adopted in 2014. The "Cast Iron Main Replacement" program includes 428 miles of main and 8,625 service lines and was expanded to include 66 miles of large-diameter cast iron. At an estimated cost of \$800 million,¹²³ the project involved a surcharge of \$49 annually, or \$4.08 per month, for an average residential heating customer in 2019.¹²⁴ In this same year, five years after the plan was adopted, there were still 405 miles of cast-iron mains left to be replaced, and the program had a 40-year completion target.¹²⁵

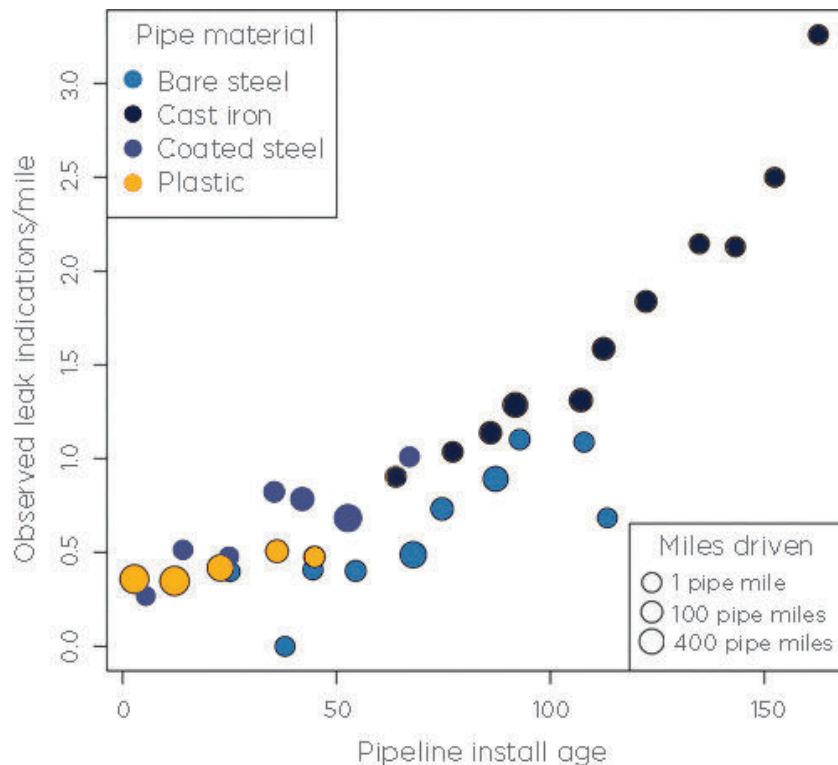
Given that the delivered cost of natural gas has remained flat for the last decade and US natural gas futures are trading below \$3.00/MMBtu through 2030+,¹²⁶ states should push utilities to set more aggressive deadlines for replacement of cast-iron pipelines, so that the entire US system is cast iron-free by 2030, and end users won't have to keep paying what can be a hefty surcharge.

Mandate Replacement of Aging Pipeline

The age of pipelines and mains matter. Approximately 35 percent of the US distribution system is over 50 years old,¹²⁷ and state policies should mandate replacement of that infrastructure, given the strong correlation between the age of pipeline infrastructure above 50 years and leakage (figure 15).



Figure 15: National estimate of methane leakage from pipeline mains in natural gas local distribution systems



Source: Z. D. Weller, S. P. Hamburg, and J. C. von Fischer, "A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems," *Environmental Science & Technology* 54, no. 14 (2020): 8958–67, <https://pubs.acs.org/doi/10.1021/acs.est.0c00437>¹²⁸

States have made it easier for LDCs to pass on the maintenance and replacement cost of distribution lines to consumers. Forty-two states, including the District of Columbia, have specific rate mechanisms that foster accelerated replacement of pipelines, but the programs are still allowed to be completed over a 20- to 40-year time horizon, which somewhat defeats the point of an accelerated replacement program.¹²⁹ These policies should be expanded to all 50 states, and deadlines for replacement should be set to 2030.

Adopt State Level Methane Reduction Targets for Gas Utilities

States can accelerate the environmental performance of the pipeline system by adopting methane reduction targets for utilities or mandates.¹³⁰ Currently, California is the only state that has set a methane reduction target for gas utilities. The state has also tied its utility rates to reducing methane emissions from natural gas use.

The California Public Utilities Commission decision implemented the following directives:



1. Annual reporting for tracking methane emissions
2. Twenty-six mandatory best practices for minimizing methane emissions pertaining to policies and procedures, recordkeeping, training, experienced trained personnel, leak detection, leak repair, and leak prevention
3. Biennial compliance plan incorporated into the respondents' annual Gas Safety Plans, beginning in March 2018; and emissions considered all leaks and vented emissions of natural gas
4. Cost recovery process to facilitate Commission review and approval of incremental expenditures to implement Best Practices (BPs), Pilot Programs, and Research and Development

California has set aggressive reduction targets for its utilities. A 40 percent reduction of 2015 levels by 2030 does not have to be the national standard, but if utilities are to be incentivized to accelerate improvements to their gas networks, a system-wide methane reduction target and tying utility rates to those reductions could be an effective tool.

Update Federal Pipeline Standards

The safety of the pipeline network is overseen by the Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA), while the Transportation Security Administration is the lead federal agency for pipeline security.

The PHMSA currently sets minimum pipeline standards for the US that states are able to build on. To date PHMSA regulations have been primarily focused on the safety of the pipeline system with very little consideration of the environmental impacts.

The Consolidated Appropriations Act of 2021, Division R, effective December 27, 2020, gave the PHMSA the responsibility for leak detection and repair of pipelines “to meet the need for gas pipeline safety...and to protect the environment.”¹³¹ The Protecting our Infrastructure of Pipelines and Enhancing Safety Act requires new regulations within a year of setting minimum performance standards for new pipeline infrastructure on methane leak detection and repair. Some suggested regulatory changes PHMSA could make are as follows:

Require Annual Inspections

Under the current regulations, pipeline operators must conduct periodic leak patrols during which the pipeline system is visually inspected for signs of gas leakage, such as changes in vegetation and heavy insect activity, both of which can indicate the presence of natural gas. These visual inspections are supplemented with leak surveys, in which flame ionization devices or other equipment are used to detect gas in the air.

The frequency at which patrols and surveys must be conducted depends on the nature of the pipeline system (e.g., the different types of pipe and where they are located), and those factors determine the risk to public safety. Transmission pipelines, which move natural gas from field production and processing areas to large volume customers and local utilities, are



generally considered to present the greatest risk because they carry large amounts of gas at high pressure. As such, the PHMSA regulations require transmission pipelines to be inspected more frequently than the smaller, lower-pressure distribution pipelines that deliver gas to end consumers.¹³²

The PHMSA regulations require both transmission and distribution pipelines in built-up areas to be inspected more frequently than those in less populated areas. Distribution pipelines located in business districts must be surveyed annually, whereas distribution lines in most other areas only have to be surveyed every five years.

Requiring all transmission and distribution lines to be surveyed annually—especially through newer and lower cost technologies such as drone or helicopter surveillance—and mandating prompt repair of discovered leaks would significantly improve the environmental integrity of the US pipeline network.

Under the Natural Gas Pipeline Safety Act,¹³³ states can impose additional or more stringent requirements than PHMSA on certain pipeline operators, though only on intrastate pipelines. When it comes to leak detection, only 18 states and the District of Columbia have rules governing the frequency of pipeline patrols and surveys (as of 2015).¹³⁴ Changing the rules at the federal level would be far more efficient than waiting for all 50 states to adopt these standards. Plus, they would apply to intrastate and interstate pipelines.

SoCalGas, as an example, will spend \$5.9 million in 2021 to do an aerial survey of 19,377 miles of pipelines and distribution lines, including the cost of data analysis and leak response.¹³⁵ For a very rough approximation, that amounts to \$304/mile (and this is on the high end of industry estimates and is not counting a lower cost of using drones). If the entire 2.5 million miles of US pipeline infrastructure was surveyed in a year, that would be a total cost of around \$760 million, or 2 percent of what was spent by the industry on infrastructure in 2019. On a \$/MMBtu basis, given the volume of gas in the pipeline system (34 trillion cubic feet), it would add at most \$0.02/MMBtu.

Change the Criteria for Which Leaks Need to Be Repaired

Under current PHMSA regulations, leaks in the pipeline system are classified as hazardous or nonhazardous. The classification of a leak as hazardous or nonhazardous is generally based on its proximity to humans and property rather than its size; leaks in built-up areas are treated as more hazardous than those in remote locations. Therefore, leaks in isolated areas may be classified as nonhazardous and left unrepaired, even if they emit substantial amounts of natural gas.¹³⁶

PHMSA classifies leaks into three categories with these directives: Grade 1 leaks are hazardous and must be cleared immediately. Grade 2 leaks are potentially hazardous and should be repaired within one year according to the Department of Transportation requirements. Grade 3 leaks are nonhazardous and must either be repaired or monitored annually.¹³⁷

Just five states—Florida, Kansas, Maine, Missouri, and Texas—have adopted their own safety regulations, establishing time frames for the repair of nonhazardous leaks. In all other states,



pipeline operators can and often do leave such leaks unrepaired for months or even years, regardless of their environmental impacts as state utility commissions do not have the authority to regulate for environmental outcomes. PHMSA therefore needs to classify leaks according to the environmental impact, not just the safety impact.

Not only are utilities not required by law to fix nonhazardous leaks, but since a Supreme Court ruling of 1935 (*West Ohio Gas vs. Public Utilities Commission*), utilities are able to recoup the costs of leaked gas by passing them on to customers via their rate base. Pipeline operators are able to recover the cost of the gas, measured as the difference between gas flows into and out of the pipeline system. There is very little scrutiny of whether claimed gas losses are truly unavoidable. If a leak can be economically repaired, it should not be considered unavoidable, and thus the pipeline company should not be able to recover the cost of that lost gas.

Require All Leaks Be Reported

While pipeline operators are required to report to the PHMSA the number of leaks repaired each year, they are generally not obligated to report the number of unrepaired leaks nor the volume of gas that is lost through such leaks. This makes it impossible to get an accurate sense of how much gas is being lost across the US system from nonrepaired leaks. A first step would be mandating that all unrepaired leaks should be measured and reported to the PHMSA.

Moreover, operators do not quantify the volume of gas lost through such leaks. This makes it difficult for regulators and others to assess the extent of gas leakage. To facilitate such assessment, operators should be required to accurately measure the volume of gas lost through leaks. The results of these measurements should be reported to the PHMSA. The PHMSA should make the reported measurements available to other interested parties.

The PHMSA must also require that upstream companies quantify and include leaks from gas gathering systems. (A gathering system usually consists of multiple pipelines laid in one area that are designed to “gather” the product that is produced from multiple wells to a central point—for example, a compressor station, a storage facility, or a larger transmission pipeline. A gathering system may consist of hundreds of miles of pipelines gathering gas from hundreds of wells in an area, or it may be just a few small pipelines gathering the product from a handful of wells. One study surveying oil and gas company operations indicated that methane emissions from gathering are substantially higher than the current EPA greenhouse gas inventory suggests, and that they are equivalent to 30 percent of the total methane emissions in the natural gas systems greenhouse gas inventory.¹³⁸

The PHMSA has updated safety rules in the past. Triggered by the 2015 Aliso Canyon incident—a massive gas leak from an underground storage facility near Los Angeles that released approximately 100,000 tons of methane¹³⁹—PHMSA finalized a new rule for natural gas storage facilities in January 2020. The new rule addressed critical safety issues related to downhole facilities, including well integrity, wellbore tubing, and casing.¹⁴⁰

For the 300,000 miles of US transmission lines, a policy tool already exists to incorporate many of these changes, though to date has been rarely used by pipeline companies. In April 2015, the Federal Energy Regulatory Commission issued a Policy Statement in Cost



Recovery Mechanisms for Modernization of Natural Gas Facilities, effective from October 2015.¹⁴¹ The policy statement permits interstate natural gas pipelines to seek implementation of surcharges or cost trackers designed to recover the costs of modernizing their facilities in response to the PHMSA, US Environmental Protection Agency, and other government safety and environmental initiatives. The policy statement on cost recovery could be used to implement PHMSA regulatory changes.

Recommendation 2. Expand on Existing Regulatory Authority to Allow for Retrofitting the Transmission and Distribution System for More Hydrogen Usage in the Pipeline Network, and Increase R&D Funding to Test the Integrity of the Pipeline System with Greater Levels of Hydrogen and Other Zero-Carbon Fuels.

If the existing pipeline infrastructure is brought up to the high standard outlined above, it would significantly reduce natural gas's overall emissions contribution to climate change. However, policies can be put into place now that also facilitate compatibility with low-carbon and zero-carbon fuels. As many of the technical questions surrounding how best to blend hydrogen and other zero-carbon fuels into our existing gas system are answered over the next few years, more detailed policy proposals around retrofits will be outlined and will be the subject of subsequent work by the authors.

But states could start by conducting an inventory of their pipeline infrastructure and what metallurgy it consists of to identify which parts can become more compatible with increased hydrogen usage.

Utilities and commissions can also identify what sections of the pipeline network and end users can initially be modified for hydrogen blending, taking a step-by-step approach to modifying the gas network versus having to make the entire system compatible with hydrogen blending at once.

As pilot projects over the next five years¹⁴² start to identify the compatibility of certain materials with hydrogen and to what percentage a blend of hydrogen is safe, states should consider adding in specific rate add-ons that allow for modifications to accommodate hydrogen if those modifications can be made without an undue burden on ratepayers, especially lower income groups. States could also start to require that mains replacement programs use hydrogen compatible plastic pipes.

In addition to the two specific categories of policy recommendations detailed in this section, broader decarbonization policy approaches could be adopted, such as a zero-carbon gas standard to spur development of hydrogen. Other approaches, outside the scope of this paper, include:

1. An enhanced 45Q tax credit to support development of CCUS on natural gas-fired plants¹⁴³
2. Alignment of state and local policies for utilities with a zero-carbon system¹⁴⁴



3. Financial incentives to drive decarbonization of energy use in homes and businesses¹⁴⁵

Decarbonizing the molecules flowing through the gas network will require significant policy support, in the same way renewable portfolio standards drove development of solar and wind capacity. The amount of gas with CCUS, hydrogen, biogas, and synthetic methane that are in the pipeline system will be a function of government policies to increase production of those low- and zero-carbon fuels. Expanded government tax credits and other production incentives are options that could be adopted.

Looking ahead also involves creating the steps to get there. Repairing and retrofitting the US natural gas pipeline network will require a concerted effort and significant short-term investments, but making use of the infrastructure already in place could offer a prime route for speeding and cost-effectively making the considerable changes needed to decarbonize the energy sector. With 34 trillion cubic feet of natural gas currently flowing through the pipeline system every year, and that volume expected to continue through much of the next decade, many of these repairs and retrofits can be made without incurring a huge cost to end users. The next decade offers a unique opportunity to use the demand for natural gas in our economy to facilitate the transition toward a net-zero future.



NOTES

1. Because the heating value of hydrogen is about one-third that of natural gas on a volumetric basis, the 20 percent of the energy that comes through as hydrogen would take up about three times the volume of the natural gas it replaced, leading to 1.4 times the volume ($0.8 + 3 \times 0.2$). Email correspondence with Professor Jack Brouwer, UC Irvine.
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