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NZIP
Net Zero Infrastructure Program

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WHITE PAPER

# Natural Gas Infrastructure in the United States: Evolving Towards a Net-Zero Emissions Future

*Map Image Credit: U.S. Energy Information Administration*

# Acknowledgements

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# List of Acronyms

| | |
|---|---|
| ASTM | American Society for Testing and Materials standards |
| BECCS | Bioenergy with Carbon Capture and Storage |
| CCUS | Carbon Capture, Utilization and Storage |
| CNG | Compressed Natural Gas |
| DOE | United States Department of Energy |
| EIA | Energy Information Administration |
| EPA | United States Energy Protection Agency |
| FERC | Federal Energy Regulatory Commission |
| GHG | Greenhouse Gas |
| GHGI | EPA US Greenhouse Gas Inventory |
| ICAO | International Civil Aviation Organization |
| IRA | Inflation Reduction Act |
| LCFS | California Low Carbon Fuel Standard Program |
| LDAR | Leak Detection and Repair |
| LFG | Landfill Gas |
| LNG | Liquified Natural Gas |
| NZIP | Net Zero Infrastructure Program |
| PHMSA | Pipeline Hazardous Materials and Safety Administration |
| REPAIR | Rapid Encapsulation of Pipelines Avoiding Intensive Replacement (ARPA-E Program) |
| RFS | EPA Renewable Fuel Standard |
| RIN | Renewable Identification Number credit; EPA Renewable Fuel Standard |
| RNG | Renewable Natural Gas |
| SAF | Sustainable Aviation Fuel |
| SNG | Synthetic Natural Gas |
| US | United States |

# Abstract

In the face of global commitments to net-zero emissions energy systems by mid-century, decision-making processes are shifting towards practical strategies to achieve ambitious economy-wide decarbonization goals. Policymakers, companies, investors, consumers, and technical communities are seeking better data, actionable insights, and increased collaboration to gain a holistic understanding of the role of natural gas infrastructure in today's energy systems and its potential to support the energy systems of the future.

Existing natural gas infrastructure in the United States has been vital for energy security and system reliability, with its ability to handle seasonal demand peaks and provide long-term fuel storage. While existing and upcoming policy initiatives aiming to increase electrification infrastructure will influence natural gas and fossil fuel reliance in the United States, it is understood that the natural gas infrastructure will continue to provide a stable and reliable fuel delivery network for the foreseeable future.

The natural gas infrastructure in the United States comprises an extensive network of pipelines, storage facilities, and processing plants. However, this infrastructure exhibits a wide range of ages, and its modernization is essential for achieving decarbonization goals. With a highly segmented and diverse range of natural gas infrastructure, a comprehensive analysis of the current infrastructure is necessary to identify areas that need upgrading, repurposing, retirement, or replacement to achieve full-scale decarbonization.

This white paper explores the important role natural gas infrastructure plays in the United States energy system and discusses key factors that inform the scope of available decarbonization pathways. These pathways include the deployment of low-carbon fuels such as Renewable Natural Gas (RNG), synthetic natural gas (SNG), and hydrogen, as well as implementing carbon capture, utilization, and storage (CCUS) technologies, modernizing infrastructure, embracing renewable energy, and investing in innovation to control and reduce emissions.

Furthermore, the gaps in current low-carbon fuel regulatory frameworks and infrastructure investments required for advancing decarbonization technologies and enhancing emissions controls highlight the need for a synergistic and region-specific approach to facilitate an effective natural gas energy transition. To achieve full-scale decarbonization, it is imperative to understand the current infrastructure, explore available decarbonization pathways, and embrace coordinated decarbonization strategies tailored to specific regions.

# Executive Summary

GTI Energy’s Net-Zero Infrastructure Program (NZIP) aims to provide insights on how to best utilize natural gas infrastructure to accelerate the transition to net-zero energy systems. These insights will be regularly updated, incorporating stakeholder input, the latest research, policy developments, and technological advancements. Through NZIP, GTI Energy is driving the national vision for integrated energy systems, empowering stakeholders to navigate the complexities of the energy transition and make decisions that align with the net-zero emissions future.

The program focuses on the following key areas:

- **Data-driven Analysis:** Through comprehensive data collection and analysis, NZIP generates insights on the performance, capabilities, and potential of natural gas infrastructure in the context of net-zero energy systems. This data-driven approach enables stakeholders to make informed decisions and develop effective decarbonization strategies.
- **Actionable Recommendations:** NZIP provides actionable recommendations based on the analysis of natural gas infrastructure. These recommendations help policymakers, investors, and operators align their decisions with the transition to low-carbon energy systems. By incorporating the latest research and policy developments, NZIP ensures that recommendations are up-to-date and relevant.
- **Collaborative Engagement:** GTI Energy actively engages with stakeholders, fostering collaboration among policymakers, industry experts, investors, eNGOs, consumers, and other key players. This collaborative approach ensures that insights and recommendations are informed by diverse perspectives, enhancing their relevance and effectiveness.
- **Adaptability and Continuous Improvement:** NZIP recognizes the dynamic nature of the energy landscape and commits to continuous improvement. The program will be regularly updated to incorporate the latest findings, emerging technologies, and stakeholders' input. This iterative process ensures that the national vision for integrated energy systems remains relevant and adaptable.

Through a series of white papers, webinars, and workshops, NZIP aims to foster meaningful dialogue to ensure that the transition to a reliable, safe, and sustainable energy future is supported by informed decision-making, collaboration among stakeholders, and ongoing discussions surrounding the evolution and adaptation of existing infrastructure in the United States.

With the rise of electrification, renewable energy integration, and a growing interdependence between gas and electric systems, the gas system acts as a crucial backbone, ensuring a stable and consistent energy supply. Its flexibility and ability to balance fluctuations in demand, especially during peak periods or intermittent renewable energy generation, enhances the overall reliability of the electric grid. Therefore, investments in this function must be valued appropriately, recognizing the indispensable contribution it makes to the sustainability and resilience of our energy infrastructure.

However, as the need to accelerate transition to the net-zero emission energy systems becomes urgent, it is important to plan for the development and expansion of decarbonized assets and reduce reliance on incompatible infrastructure simultaneously. The challenge with some legacy infrastructure materials lies in their potential incompatibility with the emerging low-carbon fuel molecules, as well as the limited remaining lifespan to serve the current energy markets. Existing infrastructure may not be suited to address decarbonization needs and may require updating and enhancement to transport low-carbon gases like hydrogen. While there have been major pipeline replacement accomplishments over the last few decades, there still remain some opportunities to address the material integrity and emission concerns of aging infrastructure in the natural gas industry.

Embracing the replacement of aging pipelines is a crucial step toward enhancing the efficiency of the existing natural gas infrastructure and mitigating emissions. This strategic move not only aligns with our environmental goals but also proves to be a wise investment. Modern pipelines, aside from being suitable for minimizing methane emissions, are more compatible with low-carbon gases. By phasing out the legacy incompatible pipelines, we not only pave the way for emission reductions but also ensure that our investments are future-proof. These new pipes are not just conduits for natural gas; they are versatile infrastructural assets that can be easily repurposed, making our investment today a sustainable choice for tomorrow. Moreover, leveraging the existing rights-of-way and delivery networks of natural gas can facilitate the integration of decarbonization solutions, such as utilizing the infrastructure to transport domestically produced alternative fuels. However, additional policies, incentives, and addressing jurisdictional challenges are necessary to ensure a reliable and resilient energy system.

In recent years, natural gas utilities in the United States have committed to reducing carbon emissions through various decarbonization strategies. They understand that achieving a net-zero energy system requires a multifaceted approach. While technological advancements are important, gas operators are also adopting approaches such as electrifying compression assets, using advanced leak detection tools for extensive surveys, and prioritizing the replacement of old infrastructure to decrease greenhouse gas emissions and promote sustainability. Investments are being made in infrastructure expansion, pipeline extensions, and securing procurement contracts to encourage the use of emerging low-carbon fuels throughout the supply chain. Since market drivers and cost efficiency will significantly impact the deployment rate and selection of decarbonization solutions to meet the mid-century net-zero targets many companies have committed to, it is crucial to adapt policies, foster collaboration among stakeholders, and provide financial support to achieve a sustainable energy future.

By exploring the current landscape and discussing future developments, this white paper serves as an informative guide, presenting an overview of the current state of natural gas infrastructure in the United States and discussing its evolution and adaptation in alignment with decarbonization goals. It emphasizes the need for collaborations, investments, and technological advancements to upgrade and expand infrastructure, ensuring it continues to support low-carbon, cost-effective energy systems in the future. Opportunities and considerations in this report include:

1- Direct emissions management methods that curtail fugitive and planned emissions associated with the entire natural gas value chain (e.g., carbon capture, utilization, and storage, improved emissions detection and quantification, and replacement of aging infrastructure) and their potential to reduce emissions at their source

2- Emerging low-carbon fuels to decarbonize the gas supply (e.g., renewable natural gas, syngas, biogases, hydrogen) and their current deployment and future outlook

3- Implications for policies and action in the acceleration of available decarbonization solutions

# Introduction

## Progress towards net-zero

The natural gas industry is influential across many energy demand sectors in the United States. Increased demand growth for energy, along with an industry-wide effort to significantly reduce carbon emissions by 2050 has necessitated further decarbonization opportunity analysis of the natural gas industry. Therefore, GTI Energy developed the Net Zero Infrastructure Program (NZIP) to provide a baseline framework of asset decarbonization potential across the entirety of the natural gas value chains. The natural gas infrastructure's capacity to store and transport substantial amounts of energy to fulfill seasonal and peak-day energy demands is a crucial factor that must be taken into account when developing decarbonization pathways as it plays a significant role in ensuring energy reliability. Thereby, NZIP addresses the requirements for capitalizing on the benefits of gas infrastructure while simultaneously pursuing innovative solutions for economy-wide decarbonization.

Numerous natural gas utilities have pledged to significantly reduce carbon emissions with various decarbonization methods over the coming decades. The following decarbonization solutions are commonly recognized priorities to ensure the least disruptive and most economical transition towards net-zero emission energy systems:

- Decarbonization efforts will importantly need to prioritize sectors in which it is difficult to abate emissions such as the industrial, transportation, and power generation sectors.
- Leveraging existing natural gas infrastructure to deliver emerging low-carbon fuels provides more practical pathways for energy consumers and minimizes potential customer disruptions.
- Scaling up the integration of existing solutions known to reduce emissions will accelerate decarbonization. This includes:
    - Reducing fugitive emissions with improved leak detection methodologies.
    - Upgrading and repairing higher-risk pipelines.
    - Improved energy efficiency and building optimization initiatives.
    - Integration of low-carbon gases with the existing infrastructure.

Natural gas infrastructure is extensive and heterogeneous in age and utilization across the United States (Figure 1). Thus, these multifaceted decarbonization efforts will need to occur simultaneously in the pursuit of effective decarbonization of the natural gas industry. National decarbonization planning will also involve a comprehensive understanding of regional energy demands, delivery and climate constraints, and cost- conscientious analysis of the available decarbonization solutions.

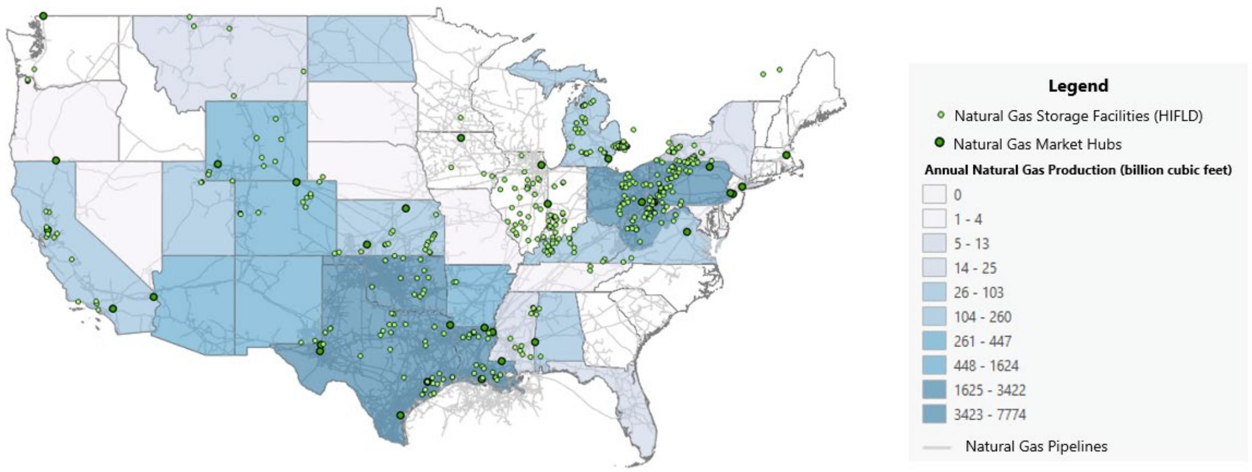


*Figure 1: Natural Gas Infrastructure Pipeline & Storage Map (Source: HIFLD[1]; EIA[2,3])*

[1] Homeland Infrastructure Foundation-Level Data (HIFLD), "Natural Gas Storage Facilities," Source
[2] US Energy Information Administration, "US Energy Atlas, Natural Gas Trading Hubs," Source
[3] US Energy Information Administration, "Natural Gas Interstate and Intrastate Pipelines," Source

# The Landscape of Evolving Natural Gas Infrastructure

## Natural Gas Investments

The modern natural gas industry was formed in the US in the mid-19th century, and the first large-scale natural gas pipeline, the Columbia Gas Transmission pipeline, was constructed in 1891. Over the past 130 years, the condition and extent of natural gas infrastructure have been greatly impacted by the historical economic aspects of the entire natural gas industry.

In the early 1900s, natural gas pipelines began to expand across the US, connecting production areas with major cities and industrial centers. This expansion facilitated the growth of the natural gas industry and the widespread use of natural gas as a fuel. In 1938, the Natural Gas Act was enacted, granting the Federal Power Commission (later succeeded by the Federal Energy Regulatory Commission (FERC)) authority to regulate the construction and operation of interstate natural gas pipelines. This regulatory framework provided stability and oversight to pipeline investments.

In the 1970s and early 1980s, there was a surge in pipeline investments to expand infrastructure and alleviate supply constraints that were being experienced due to natural gas shortages. Furthermore, in the 1980s and 1990s, the natural gas industry underwent deregulation, which resulted in increased competition and pipeline infrastructure investments. The shale gas revolution in the 2000s emerged when hydraulic fracturing and horizontal drilling unlocked vast reserves of shale gas, which led to a surge in natural gas production that required significant pipeline investments to handle the new supply.

As seen in Figure 2, there has been limited expansion in total miles of natural gas gathering and transmission pipelines since this boom in pipeline investments.[4] The Pipeline and Hazardous Materials Safety Administration (PHMSA) describes that the total transmission network has slowly grown from 285,000 to 301,500 miles between 1984 and 2021. The gathering network is comparatively small and decreased from 37,000 to 17,000 miles over the same timeframe. However, after 2019, gathering infrastructure suddenly grew to nearly 110,000 miles, mainly due to the imposed gathering pipeline reporting mandates. On the other hand, Figure 3 shows that distribution capacity continues to grow steadily during this time period with 1.29 million miles in 1984 and 2.34 million miles in 2022.

Historically, gathering pipelines were characterized by their small diameter and low pressure, primarily located in remote rural areas, resulting in minimal regulatory oversight due to their perceived low impact on public safety. However, with the shale and fracking boom, these pipelines expanded in size and pressure, at times resembling large transmission pipelines. This growth increased both their mileage and the associated risks to people and the environment. In 2022, recognizing these heightened risks, PHMSA initiated regulatory measures to oversee gathering pipelines, marking a shift from an almost entirely unregulated system to a proactive approach aimed at ensuring safety in an evolving energy landscape.

[4] PHMSA, "Annual Report Mileage for Natural Gas Transmission & Gathering Systems," 1 June 2023. Source

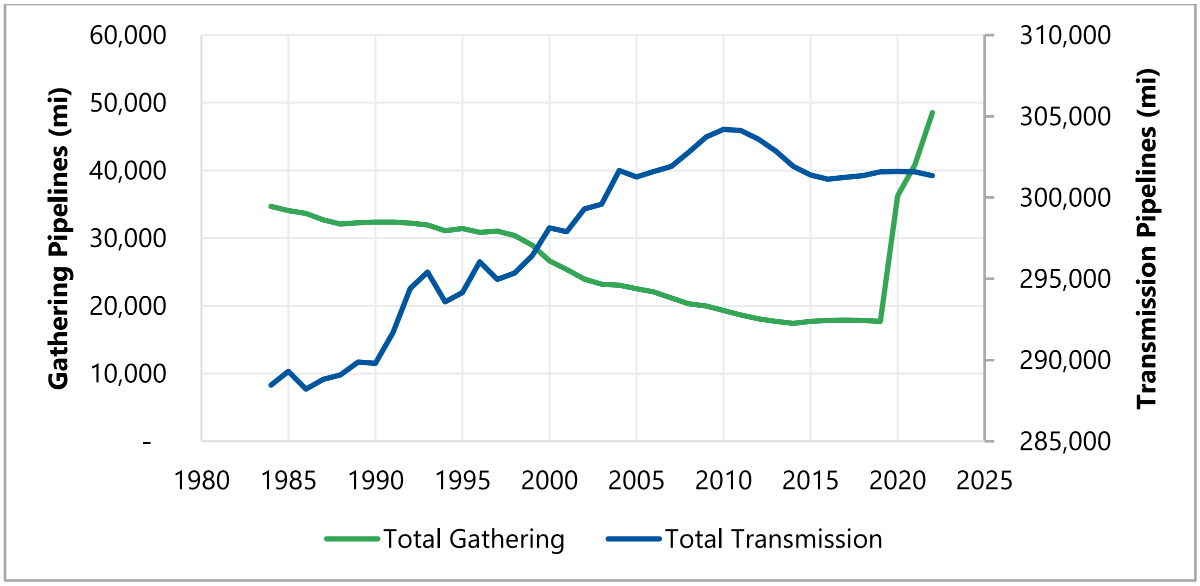


*Figure 2: Total pipeline miles for gathering and transmission segments of natural gas supply vs. Time (Source: PHMSA)*

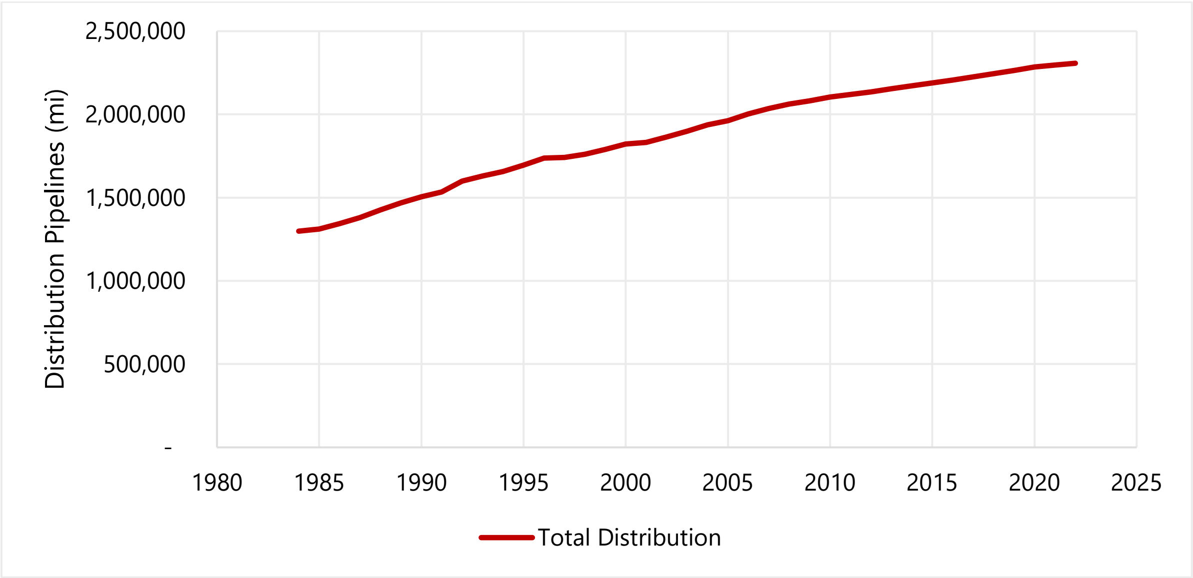


*Figure 3: Total pipeline miles for transmission segment of natural gas supply vs. Time (Source: PHMSA)*

Recently there has been an increased focus on pipeline safety and environmental considerations. Investments have been made to upgrade aging infrastructure, enhance safety measures, and address environmental impacts associated with pipeline construction and operation. In 2011, PHMSA issued the Call-to-Action Letter to Local and State Organizations, in which there is an acknowledgement that aging natural gas infrastructure pose certain material integrity concerns and thus require more immediate repair and replacement prioritization[5]. In response, numerous natural gas utilities initiated extensive pipeline replacement programs to reduce the number of aging materials in their assets. One example of these efforts is the 3,000-mile infrastructure replacement program set forth by People's Gas, a distribution company that serves the City of Chicago, which is estimated to be completed by 2040, with a total cost of $8 to $11 billion dollars[6,7]. According to ARPA-E, aging distribution pipelines can cost roughly $1 to $10 million dollars per mile to replace depending on the pipeline's location[8]. To encourage cost minimization of pipeline replacements, ARPA-E introduced the Rapid Encapsulation of Pipelines Avoiding Intensive Replacement (RAPID) in early 2020, a $38 million dollar research funding program that seeks to explore methods to rehabilitate distribution pipes rather than remove them, thereby eliminating the need for costly excavations.

Natural gas pipeline replacements currently far exceed pipeline expansions and new pipeline developments. Since 2018, EIA estimates there have been 33 new natural gas pipelines and 48 pipeline expansions in the US[10]. There were a significant number of pipeline projects through the late 1990s and 2000s, ahead of a slowdown through the mid-2010s and a slight recovery into 2020. Total annual spending on new pipelines and expansions has risen from roughly $1B to $10B between 1995 and 2020, and future spending is projected to be an average $19B through 2026[9]. However, through its maintenance and replacement programs, PHMSA distributed nearly $400M to publicly- and community-owned natural gas systems[10]. Replacing all pipelines is projected to cost around $270B, and natural gas utilities invest $32B annually to improve the distribution network's safety[11].

Major shifts in capital expenditure costs have been observed over the last decade for distribution pipelines. According to the American Gas Association, costs for construction of distribution and transmission pipelines, adjusted for inflation have grown from 2011 to 2021 by 166% and 1.9%, respectively[12]. This dramatic cost increase for distribution pipelines is mostly likely attributed to the extensive pipeline replacement programs for cast-iron and bare steel during this period.

Natural gas demand varies across the United States, which impacts the availability and state of infrastructure at the regional level. Consumption of US natural gas is most commonly reported as a total rate, but it is frequently analyzed by sector as well. At a high level, natural gas can be consumed within the supply chain, but the vast majority is delivered for end-use in various sectors. The major segments in the natural gas supply chain include production, gathering &

[5] DOT PHMSA, 2011. PHMSA Call to Action Letter to Industry. Source
[6] People's Gas, 2019. Replacing Pipelines to Reduce Methane Emissions. Source
[7] RMI, 2020. A New Approach to America's Rapidly Aging Gas Infrastructure. Source
[8] ARPA-E, 2020. Rapid Encapsulation of Pipelines Avoiding Intensive Replacement. Source
[9] US Energy Information Administration, US natural gas pipeline projects. Source
[10] PHMSA NGDISM Grant Program Now Open for Applications. Source
[11] AGA Playbook 2023. Source
[12] American Gas Association, 2023. TABLE 12-1 Gas Utility Construction Expenditures by Type of Facility. Source

boosting, gas processing, transportation & storage, and distribution. Lease fuel refers to natural gas used within the production and gathering & boosting segments in well, field, and leased operations. This amount can include gas used in drilling operations and field compressors. Plant fuel is comprised of natural gas that is used as a fuel in the gas processing segment. Lastly, natural gas for pipeline & distribution use is consumed in the operation of pipelines (primarily compressors) and distribution networks.

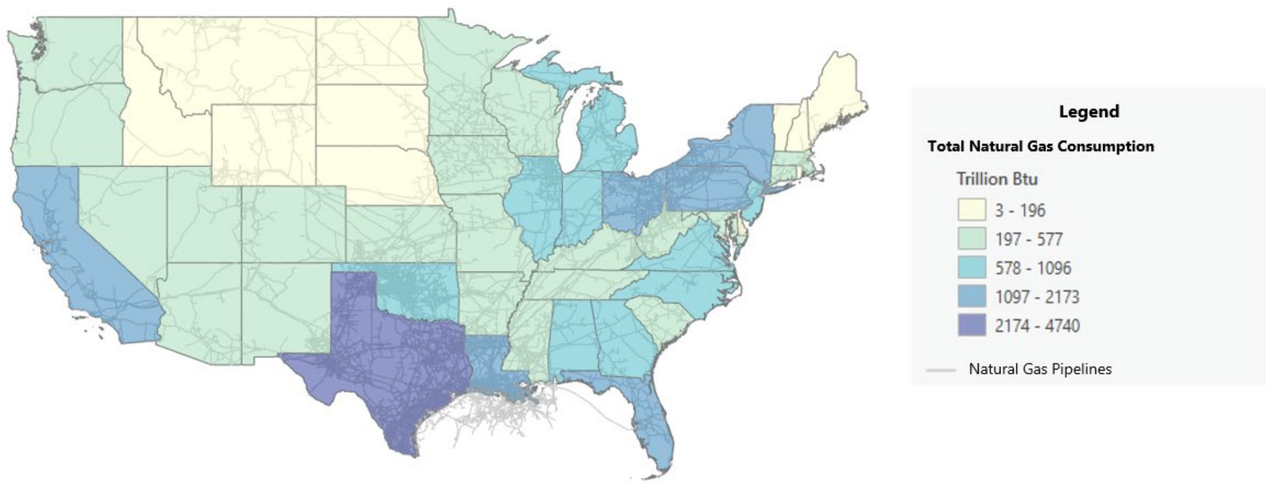


*Figure 4: Total Annual Natural Gas Consumption by State (Source: EIA[5])*

The current regional differences in natural gas demand are visualized in Figure 4 [5]. States that have the highest natural gas demand per capita are located in the southern portion of the United States. Regions with greater natural gas production generally correspond with regions of greater natural gas usage (Figure 1,4).

Five consumer sectors will be discussed in this paper. Residential consumption includes natural gas that is used in private dwellings, for heating, cooking, water heating, and other household uses. Commercial natural gas usage broadly applies to non-manufacturing establishments that sell goods or services. Restaurants, wholesale/retail stores, hotels, and federal agencies fall under this umbrella. The Industrial sector covers most of the rest of the infrastructure that supports business, which includes natural gas used for heat, power, or chemical feeds of manufacturing establishments, mining/mineral extraction sites, agricultural sites, and fisheries. Additionally, natural gas is consumed as vehicle fuel in the Transportation sector. Lastly, an energy-consuming sector is the power generation sector, which consists of electricity-only and combined heat and power (CHP) plants.

In 1930, the EIA began recording residential and commercial natural gas consumption, which rose steadily through 1970. The combined consumption of Lease and Plant sites was tracked starting in 1930, and their individual usage rates were recorded as early as 1983. Lastly, the individual demand of Industrial consumers, Pipeline & Distribution, Transportation, and Power Generation, was logged starting in 1997 (Figure 5).

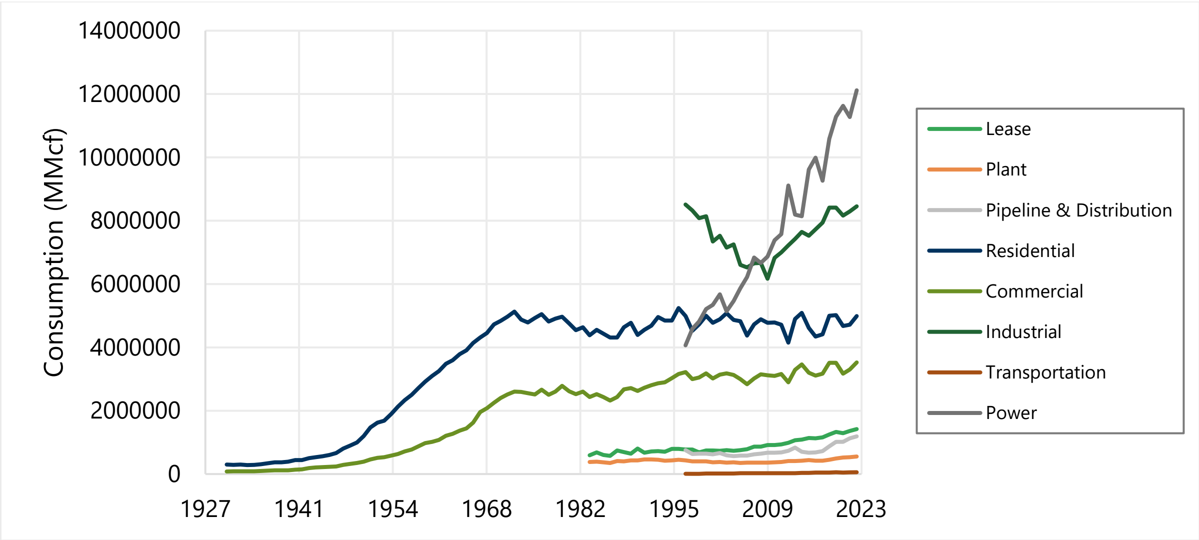


*Figure 5: Reported Annual US natural gas consumption by sector (Source: EIA[13])*

Despite relatively consistent consumption in the residential and commercial sectors, the most impactful trends since 2000 have been sharp increases in natural gas use for power generation and in the industrial sector, as seen in Figure 5. The vast US natural gas supply was unlocked in the 2000s and 2010s with the maturing of hydraulic fracturing technology. Significant coal-to-natural gas switching in electricity generation and industrial sectors occurred in the 2000s due to natural gas' high supply, lower cost, and reduced combustion $CO_2$ emissions (Figure 6). Electricity generation continues to be heavily dependent on natural gas from historically relying on both coal and natural gas. As of 2022, 39.8% of the total electricity generation was from natural gas[10]. The remaining sources of electricity generation are identified as renewables (21.5%), nuclear (18.2%), and coal (19.5%).

[13] US Energy Information Administration, "Electricity in the US," 19 July 2023. Source

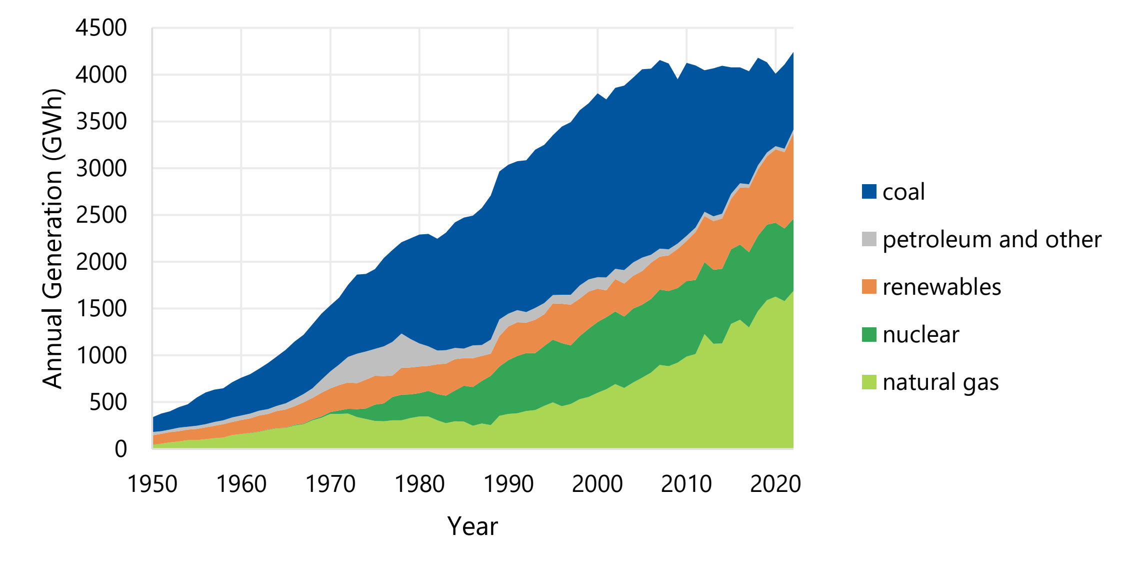


*Figure 6: Net US electricity generation by energy source (1950 -2022) (Source: EIA[14])*

The maximum switch from coal to natural gas for power generation in the United States, often referred to as the "shale gas revolution," began to gain significant momentum in the early to mid-2000s. This shift was driven by the increased availability and affordability of natural gas due to advancements in shale gas extraction techniques, such as hydraulic fracturing (fracking). While it started earlier, the revolution became more pronounced around 2008 and continued throughout the following decade. The widespread transition from coal to natural gas during this period had a substantial impact on the composition of the U.S. power generation mix, contributing to reduced carbon emissions and changes in the energy landscape. Between 2011 and 2023, 121 US coal-fired power plants retired from processing coal feedstock to be converted to burn other types of fuel. 17 of these plants were replaced with new natural gas-fired combined cycle (NGCC) plants, and the other 104 converted their boilers to burn natural gas. Of the total 316.8 GW of US coal-fired capacity that existed in 2010, 49.2 GW was retired, 14.3 GW was converted to burn on natural gas, and 15.3 GW was replaced by NGCC.[15]

With natural gas production rates that do not significantly fluctuate throughout the year, storage facilities provide the infrastructure to navigate daily and seasonal variations in demand. During summer periods of low demand, natural gas is injected into underground storage facilities. On extremely cold winter days when demand is significantly higher, the stored gas is withdrawn from these facilities. The United States possesses around 5 trillion cubic feet (Tcf) of natural gas storage capacity, with the capability to provide up to 20% of the total natural gas consumption in the cold season[16]. The continued integration of intermittent energy sources like wind and grid-scale photovoltaic electricity will signal an increased demand for storage capacity,

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[14] EIA, 2023. Electric Power Monthly, Table 1.1: US Electricity Generation by Source. Source

[15] US Energy Information Administration, "More than 100 coal-fired plants have been replaced or converted to natural gas since 2011," 5 August 2020. Source

[16] U.S. Department of Energy, 2016. U.S. Natural Gas Storage Capacity and Utilization Outlook. Source

particularly for flexible, high-deliverability storage that these underground storage facilities can provide.

The natural gas storage and delivery infrastructure was designed to reliably serve customers through spikes in heating-driven consumption during cold winter periods. Conversely, electricity transmission was designed around spikes in cooling-driven consumption in the hot summer periods. The US experiences more severe spikes in heating than cooling, so there is more seasonal variation in natural gas consumption than electricity consumption.[17] Figure 7 shows the monthly consumption rates of natural gas and electricity across all US sectors in 2022.[18]

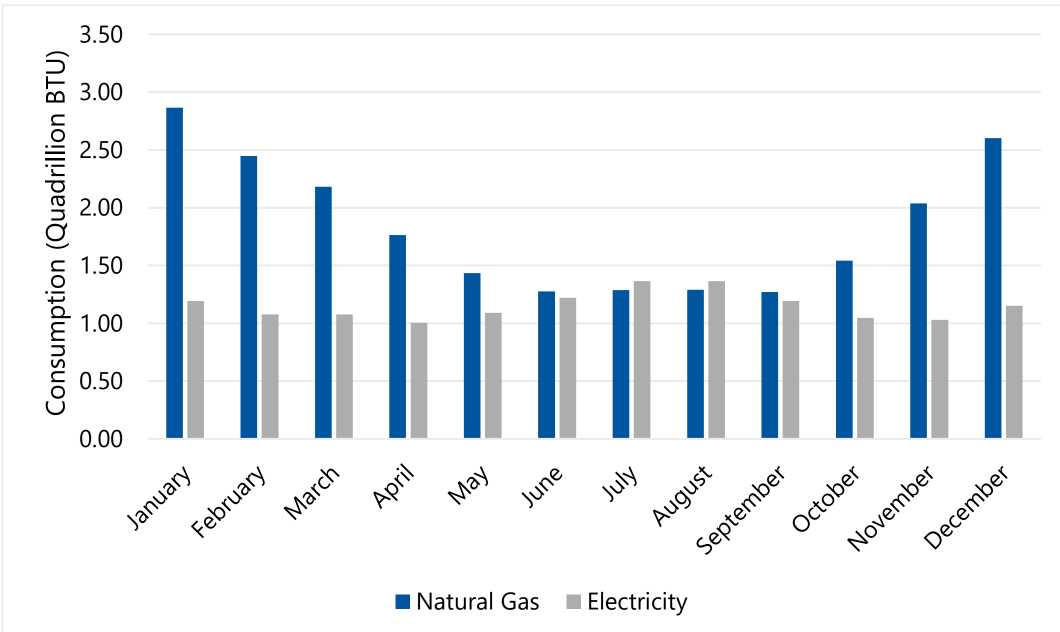


*Figure 7: 2022 Natural gas and electricity US consumption in all sectors (Source: EIA)*

Nationwide consumption of natural gas and electricity across all sectors have roughly equivalent off-season demands of 1.3 and 1.0 quadrillion BTU/month, respectively. However, cooling demand spikes electricity to 1.3 quadrillion BTU/month in summer months, and heating demand causes a more significant spike in natural gas consumption to 2.9 quadrillion BTU/month. This significant winter heating demand will make complete renewable electrification shifts costly.

Historical and projected energy demands will significantly guide the deployment of the various decarbonization options in the energy industry. To achieve lower combustion-related emissions and improve efficiency, there has been increasing interest in transitioning fossil-reliant energy systems to electric infrastructure. However, the wide range of natural gas end uses presents opportunities to ensure long-term value from the expansive natural gas networks that connect to a multitude of energy demand sectors in the U.S. It is also important to recognize the

[17] American Gas Association, "Net-Zero Emissions Opportunities for Gas Utilities," February 2022. Source
[18] US Energy Information Administration, "May 2023 Monthly Energy Review," 25 May 2023. Source

regional and seasonal variability that exists in our current energy systems to more effectively plan for the transition to a net zero economy.

The extensive and largely subterranean natural gas infrastructure in the United States, spanning about three million miles of pipelines, alongside compressors, storage facilities, and power plants, holds a substantial economic value, totaling in the trillions of dollars. With connections to nearly 70 million households and widespread use in transportation, buildings, and industry, replacing this infrastructure prematurely would lead to financial losses for owners, and resistance from various stakeholders.

Clean energy advocates have legitimate concerns about the potential for a lock-in effect stemming from investments in gas infrastructure. The extended lifespans of power plants, pipelines, and gas storage units, ranging from 25 to 80 years, create the risk of these components either perpetuating increased emissions or becoming stranded assets. However, a solution to this lock-in problem lies in adopting drop-in alternatives to natural gas—low-carbon gases such as synthetic methane capable of utilizing existing pipes, tanks, and power plants. This approach leverages the substantial investments in gas infrastructure, amounting to trillions of dollars in assets.

## The State of Natural Gas Infrastructure

### A Brief History of Natural Gas Pipeline Materials

Natural gas infrastructure materials have evolved over the last century. Early versions of natural gas pipeline distribution networks were constructed with cast iron piping and bare steel, starting in the 1870s and continuing as late as the 1950s. Bare steel is present in distribution and transmission systems, while cast iron pipes only exist in distribution systems. Material degradation as well as inherent material properties of these pipelines (e.g., low toughness) affected the integrity of these materials as threats, such as soil movement or excavation damage, acted on them. As more modern materials and techniques became available to mitigate threats, the use of these materials decreased gradually. By the late 1960s, what is now known as vintage plastic pipe became an industry-wide alternative to cast iron installations in natural gas distribution systems. In 1971, the US enacted the Corrosion Control and Requirements for Pipelines Installed After July 31, 1971, Mandate (49 CFR Part 192.)[9]. This mandate required that all installed buried pipes after July 31, 1971, must be properly coated and cathodically protected. Additionally, this federal mandate required prioritization towards higher corrosion risk pipelines to be given cathodic protection.

Another major turning point for upgrading aging natural gas infrastructure occurred with the Department of Transportation’s 2011 call to expedite the replacement and repair of cast iron and bare steel pipelines. PHMSA lists 11 causes of natural gas pipeline failures, five of which are related to some form of corrosion[19]. The precedent for replacing cast iron and bare steel pipelines was nested in the fact that these materials are at higher risk for corrosion and have

[19] Pipeline and Hazardous Materials Safety Administration, 2023. Pipeline Replacement Background. Source

also exceeded their material integrity lifetime. PHMSA currently maintains annual inventories of cast iron and bare steel natural gas pipelines for both distribution and transmission segments across the US[20,21]. Figures 8 and 9 visualize the remaining bare steel pipelines in the distribution and transmission segments of the natural gas industry. Extensive efforts to eliminate cast iron and bare steel have been made by the natural gas utilities.

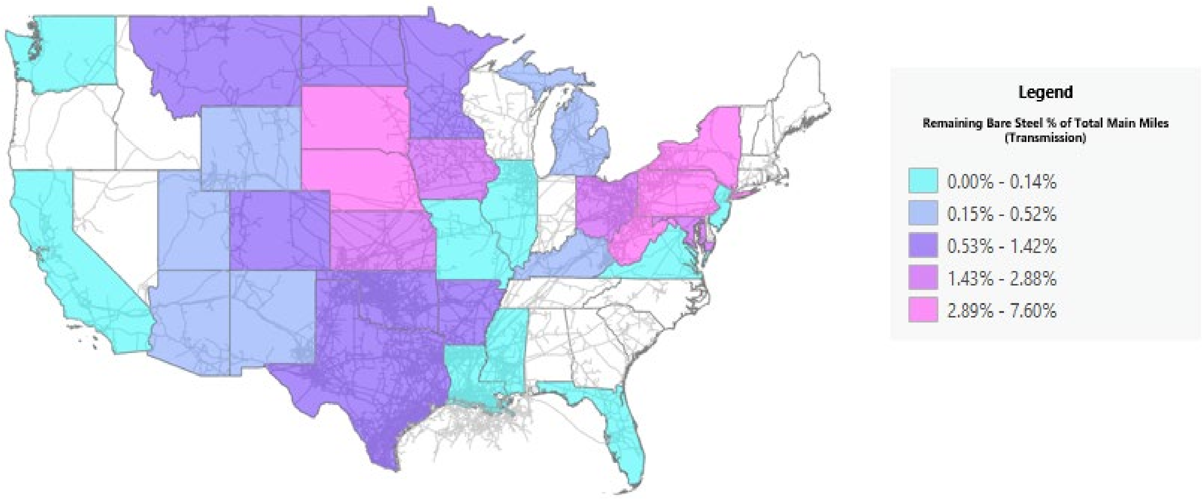


*Figure 8: Existing Bare Steel Pipeline (Main Miles) in the Transmission Natural Gas Segments*[10,11]

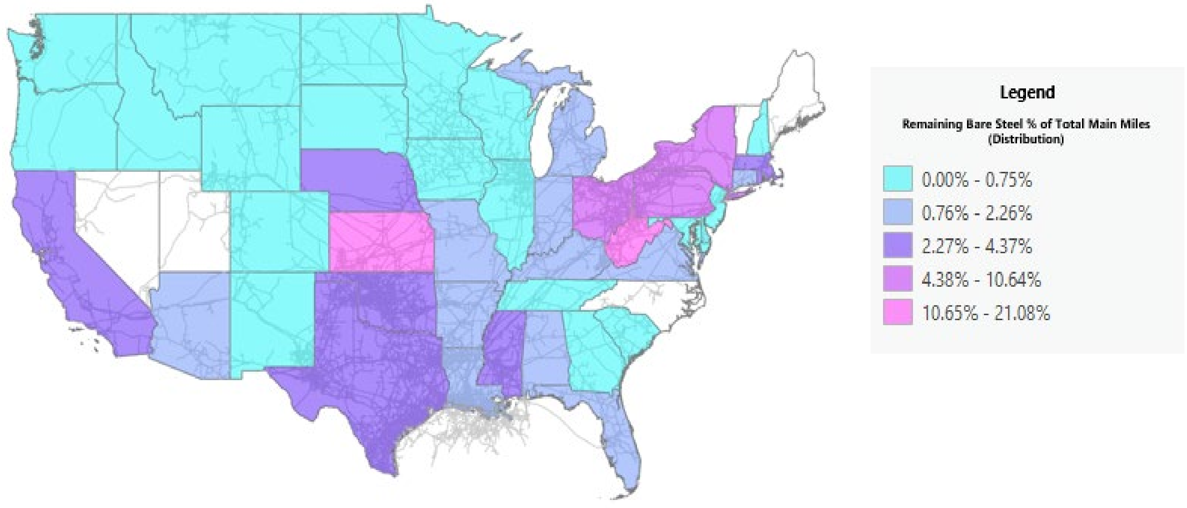


*Figure 9: Existing Bare Steel (Main Miles) in the Distribution Natural Gas Segments*[10,11]

Cast iron is deemed to pose the highest leak risk to distribution pipeline networks. Removal of cast iron and bare steel has contributed to the reduction in reported fugitive emissions in the natural gas distribution systems from 1990 to 2022[22]. The EPA Greenhouse Gas Inventory

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[20] Pipeline and Hazardous Materials Safety Administration, 2023. Bare Steel Inventory. Source

[21] Pipeline and Hazardous Materials Safety Administration, 2023. Cast and Wrought Iron Inventory. Source

[22] U.S. EPA, 2022. EPA Greenhouse Gas Emissions Inventory. Source

reports a decline from 1990 in natural gas distribution methane emissions, from 1,819 kilotons $CH_4$ in 1990 to 548 kilotons $CH_4$ in 2021[14].

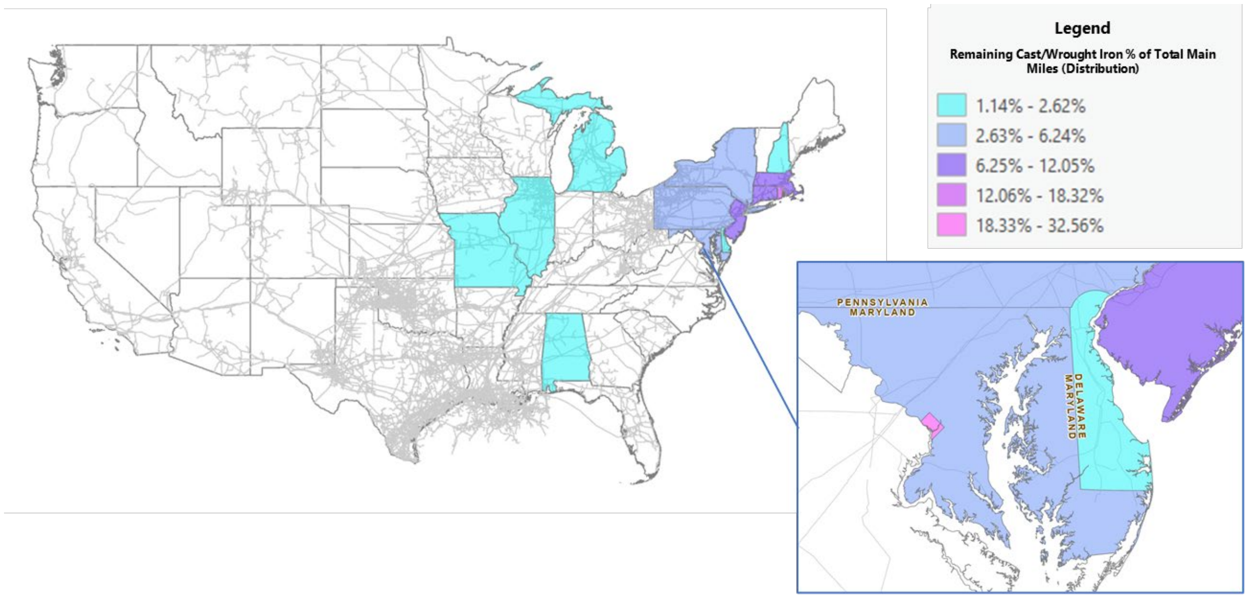


*Figure 10: Existing Cast Iron Pipeline (Main Miles) in the Distribution Segment[10,11]*

Natural gas pipeline replacement programs have succeeded in reducing cast and wrought iron main miles by over 50% from 2005 to 2022.[13] Remaining cast iron and bare steel main miles over distribution and transmission segments are visualized in Figures 8-10. Due to the availability of PHMSA data, the map aggregates data to the state level and does not illustrate specific locations of cast and wrought iron and bare steel segments. The red outline illustrates the existence of cast and/or wrought iron in a state and may not indicate there is cast and/or wrought iron throughout the state.[23]

A total of 22 states have eliminated cast iron in their distribution assets, as visualized in Figure 10. States that are currently impacted the most by cast/wrought iron and bare steel natural gas infrastructure are predominantly located in the Midwest and eastern regions of the US, with the highest concentration located in the older distribution systems of the Northeast (Figure 11).

[23] For example, in California, SoCalGas, San Diego Gas and Electric, and Southwest Gas report zero miles of cast iron pipeline in their service territories.

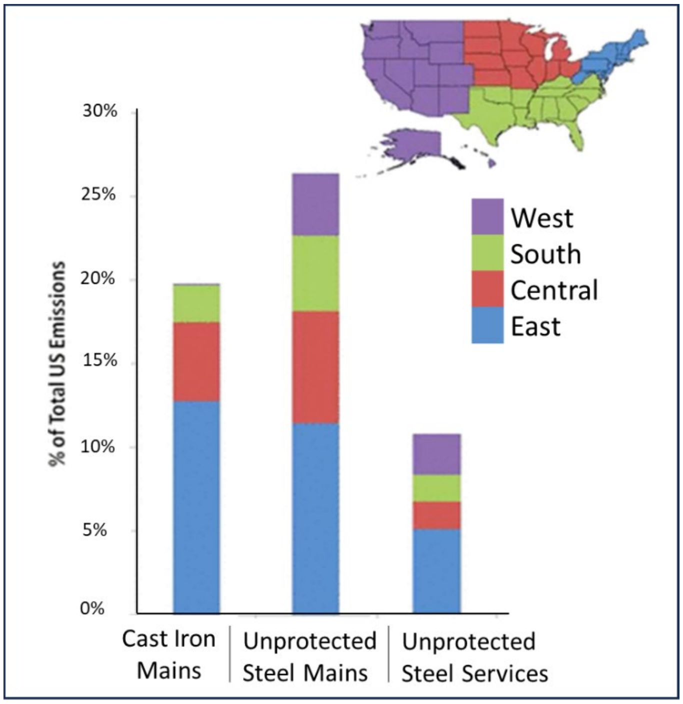


*Figure 11: Percentage of total U.S. methane emissions in 2011 from underground cast iron and bare steel pipeline leaks by region*[24]

Plastic pipelines installed in the 1960s and early 1970s currently show issues related to low ductility at the inner wall, which is associated with a phenomenon called slow crack growth (SCG). This phenomenon can lead to premature failures of pipelines well below the expected material life. The decreased material integrity caused by SCG is due to inadequately controlled manufacturing processes. In 2014, PHMSA added prohibitions on the installation of vintage plastic materials which were initially used in the 1960s. New technology developments allowed accurate manufacturing controls as well as new resin formulations that resulted in plastic pipes with higher performance and strength, such as high-density polyethylene, which are installed across distribution assets. Modern higher-density plastics such as medium-density polyethylene (MDPE) and high-density polyethylene (HDPE) were initially introduced into natural gas distribution assets in the early 1980s[24]. Due to inadequate material records of installed vintage pipelines, inventories on vintage plastics are not accurate and thus present a possible opportunity for further replacement. While an industry-wide effort to replace existing vintage plastic pipelines has not been established, some gas utilities have taken the initiative to eliminate vintage plastics in their distribution assets. At the end of 2022, PHMSA estimates that 98 percent of natural gas distribution pipelines in the US are made of plastic or steel, with one percent represented by cast and wrought iron pipe. Figure 12 visualizes the ages of main pipelines in service as of 2022.[25]

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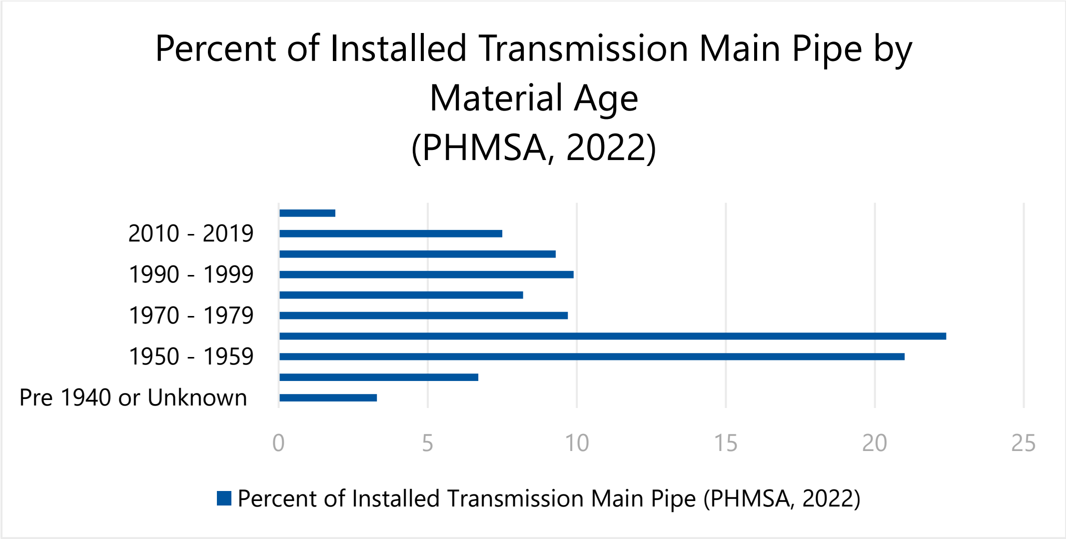
[24] Hart Energy, 2005. The history of PE pipe. Source
[25] Pipeline and Hazardous Materials Safety Administration, 2023. By-Decade Inventory. Source



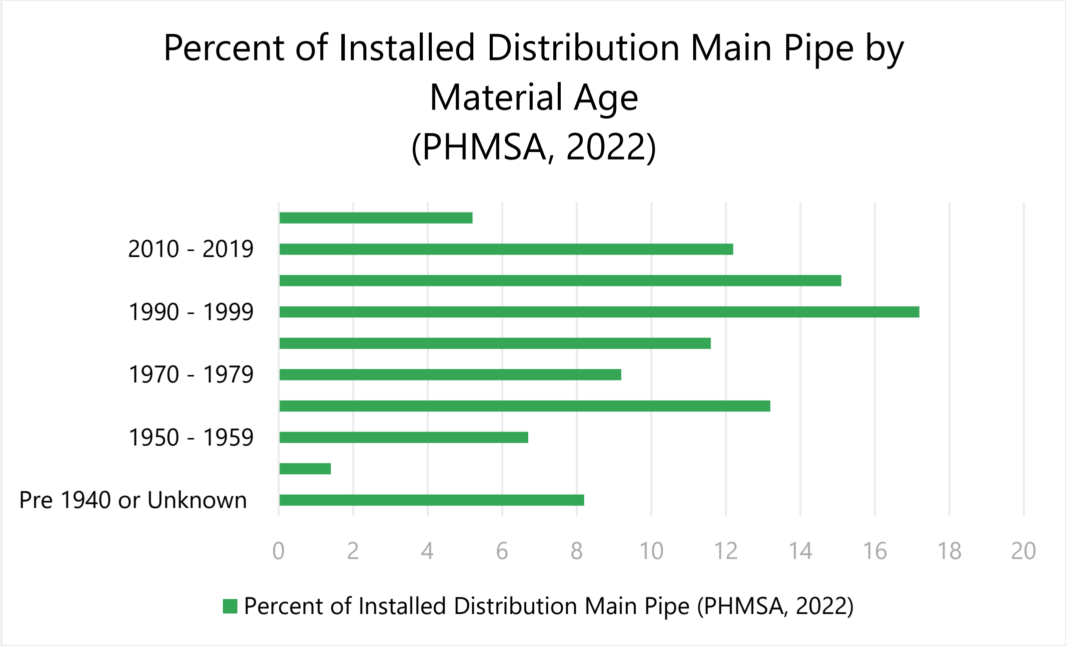




*Figure 12: Comparison of pipeline materials in service by material age (Source: PHMSA)*[15]

The pipeline materials still in service across the transmission and distribution segments are observed to include a wide range of material ages. In the current transmission system, there are documented pipelines that were installed in 1930. As with vintage plastic, manufacturing controls were not as developed. It is likely that along the more than 270,000 miles of natural gas pipeline, there are segments with an earlier installation year. This points to one of the main issues when characterizing the natural gas transmission system in the US. In the early days of the natural gas industry and up to 1970, tracking and traceability did not have the attention that they are given today. Even when there is some information available, its validity might be difficult to confirm. For example, the installation date does not necessarily correspond to the manufacturing year. The characteristics of many segments of pipelines are unknown to the operators that own them. The PHMSA "Mega Rule" Part 1 issued in 2019 enforces operators to reestablish or verify material properties in their assets to carry out integrity assessments.

Population growth and regional demand have possibly played a more significant role in the replacement of aging pipeline materials rather than the age of the pipeline materials alone. As populations grew and urbanized, the need for greater natural gas supplies strained existing pipelines, often ill-equipped to handle increased volumes. Aging pipelines, while structurally sound, often lack the capacity and safety features necessary to meet these demands. Advances in pipeline technology offered more durable and efficient materials, enhancing safety, reliability, and sustainability. The reduced quantities of older installed pipeline materials in 2022 are also attributable to the pipeline replacement efforts across both transmission and distribution segments.

Aging infrastructure is identified by PHMSA as pre-1970s infrastructure, which comprised 29% and 53% of all in-service distribution and transmission main miles in 2022.[13] Given the national average annual reduction in pre-1970s distribution and transmission main miles from 2005 to 2022, the remaining main mile pipeline replacements are expected to exceed 73.5 and 85 years, respectively. However, the total distribution segment is expected to exceed 100 years when considering the rate of service line pipeline replacements. With the current average national replacement rates from 2005 to 2022, natural gas distribution companies are also anticipated to complete the replacement of bare steel and cast-iron service lines within the next 26 years.

Pipeline replacement programs are vital to the energy efficiency and emissions management of the natural gas industry. However, the total replacement of cast-iron and bare steel pipeline materials is projected to reach completion after the mid-century decarbonization targets as defined by the natural gas utilities. Therefore, there may exist opportunities to strategize decarbonization planning with the prioritization of necessary pipeline replacements. More near future interconnections of RNG and hydrogen will likely be more suited in regions lacking cast/ wrought-iron and bare steel, both to reduce total project costs and ensure effective emissions reductions. Additionally, research surrounding less invasive methods to rehabilitate aging pipelines currently investigated with ARPA-E's REPAIR program could potentially drastically reduce replacement costs and accelerate national pipeline replacements of cast-iron and bare steel pipeline materials. With the success of pipeline replacement programs, methane leaks from premature corrosion will be mitigated. Newer, more resilient pipeline materials are necessary to ensure the efficacy of AEC interconnection projects to deliver lower emissions.

## Emissions of Natural Gas Infrastructure

According to a 2022 IEA report, natural gas, and the accompanying infrastructure will still be necessary for energy stability for most mid-century net-zero scenarios.[26] Natural gas is still considered a high-demand fuel source out to 2050 with changing mixes in gaseous fuels and carbon capture technologies. While the role of natural gas extracted from production wells may diminish in some capacity, the best-known infrastructure-compatible replacements will be other gaseous fuels such as biogases. These fuels will require a pipeline network to serve customers,

[26] IEA. World Energy Outlook 2022: Outlook for gaseous fuels. Source

which emphasizes the importance of upgrading and maintaining the natural gas pipeline network already in use today.

There are three categories of emissions associated with the natural gas infrastructure; fugitive, vented, and combustion-related emissions[25]. Fugitive emissions are one of the most significant sources of emissions for the natural gas industry. The U.S. EPA defines these fugitive emissions as originating from unintentional leaks emitted from sealed surfaces (i.e., packings and gaskets), or leaks from underground pipelines resulting from corrosion or faulty connections[27]. To address these fugitive emissions, natural gas utilities, and regulatory agencies have placed major emphasis on the improvement of leak detection and pipeline repair programs to mitigate non-combusted emissions that contribute directly to global warming. Based on the IPCC's (Intergovernmental Panel on Change) Fifth Assessment Report (AR5), methane, which is 84 times more potent in global warming potential (GPW) than CO2 on a 20-year timescale (GWP20) and 28 times more potent in GWP on a 100-year timescale (GWP100), is a significant form of emissions from the natural gas industry.

In 2021, methane was the second largest contributor of greenhouse gas emissions in the United States at 11.5% compared to $CO_2$ at 79.4%[28] based on the GWP100 values. Emissions of methane are additionally contributed by intentional releases, known as venting. Vented emissions of the natural gas industry are defined as planned or designed emissions of natural gas to the atmosphere. Venting in the natural gas industry is implemented to ensure safe, economical, and efficient operations in response to issues such as over-pressurization or undesirable gas quality. An alternative to direct releases of methane can be achieved through combustion at the source, which is referred to as flaring. Flaring reduces methane emissions by emitting $CO_2$, which is less impactful to global warming. Various system design changes are being explored to reduce flaring and venting across natural gas assets, such as through improvements in waste valorization and component pressure monitoring.

Decarbonization of the natural gas industry will have greater implications for the total greenhouse gas (GHG) emissions observed in the U.S. economy. The EPA US Greenhouse Gas Inventory identifies the largest sources of $CO_2$ emissions in the U.S. to be associated with fossil fuel combustion, including natural gas, from the power generation and transportation sectors. Direct methane emissions occur mostly from agricultural practices, enteric fermentation, landfills, and natural gas systems. Natural gas combustion contributed around 35% of $CO_2$ emissions across all sectors including electricity generation, transportation, industrial, commercial, and residential. National emissions associated with the natural gas industry vary significantly by location, as visualized in Figure 13. The emissions associated with the natural gas industry are importantly differentiated by segment, including production, transmission, storage, and distribution. Each segment of the natural gas industry requires specialized emissions management solutions and considerations.

[27] EPA, 2020. Estimate of Methane Emissions from the U.S. Natural Gas Industry. Source
[28] EPA, 2023. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021

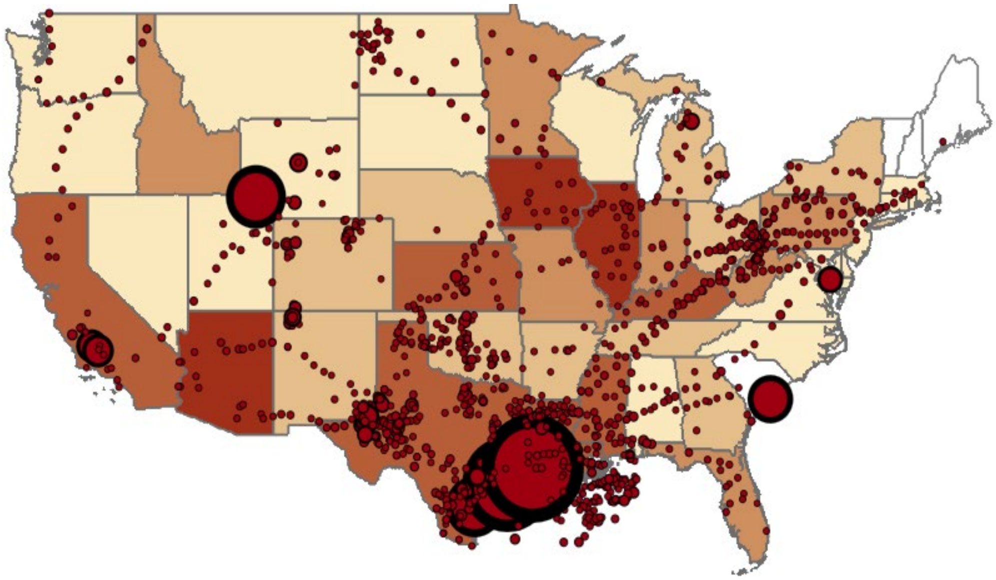


*Figure 13: Emissions associated with Petroleum and Natural Gas Systems*[29]

Figure 14 below shows the historical trend of emissions from 1990 to 2021 by each segment of the natural gas supply chain. Since 1990, each segment has experienced a decrease in fugitive emissions except for Production, which has seen an overall 45% increase mostly due to increases in Onshore Production (27%) and Gathering and Boosting (110%) segments. The production of natural gas has also been found to contribute the greatest emissions of all natural gas infrastructure segments from 1990 to 2021. Emissions management practices associated with the production segment include flaring when necessary and the minimization of venting. However, more impactful emissions reduction methodologies will need to be implemented over the Production segment to achieve the net-zero targets of the natural gas industry. Additionally, the decarbonization solutions of the Production segment will differ greatly from the Distribution, Transmission, and Storage segments of the natural gas industry.

The Distribution and Transmission- Storage segments represent the fuel delivery networks of the natural gas industry and are more extensive in scale compared to the Production segment. These segments are where the bulk of domestic pipeline capacity is located and are pivotal segments in the net-zero transition. Emissions resulting from the natural gas delivery segments are mostly associated with fugitive emission releases to the environment. Transmission, Storage & Distribution saw significant decreases in emissions, 31%, and 70%, respectively, from 1990 to 2021. The emissions reductions in these segments were significantly influenced by recent pipeline upgrades, better material maintenance, as well as more emphasis on survey and leak repair programs. Emissions management of the natural gas delivery segments poses intrinsic value to future decarbonization planning, as they represent existing networks that can efficiently deliver alternative energy carriers to future end users.

[29] US EPA, 2022. Greenhouse Gas Reporting Program Data. Source

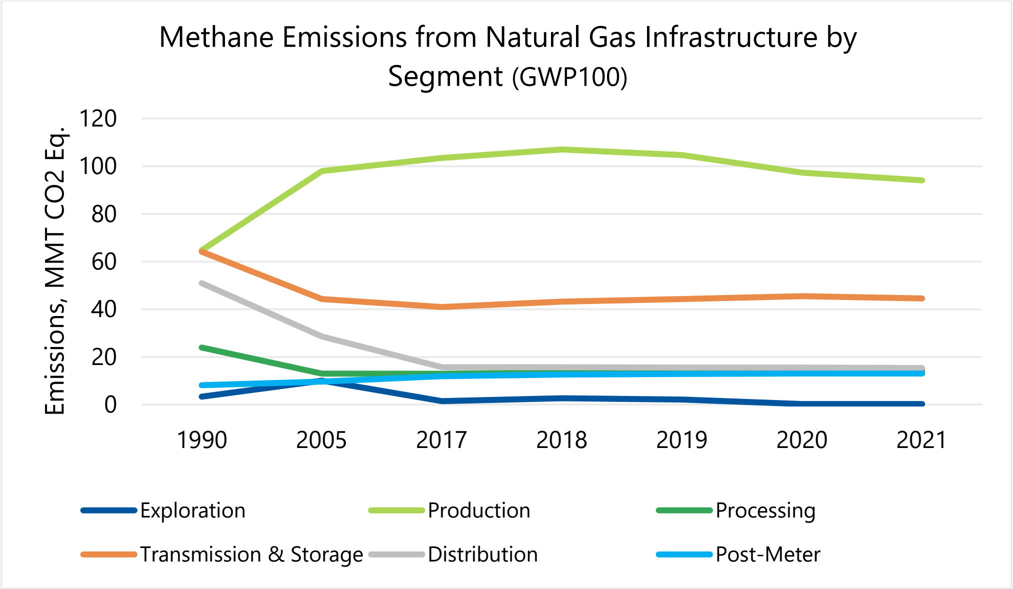



*Figure 14: Historical trend of methane emissions from natural gas infrastructure by segment*[19]

Decarbonization of the natural gas industry will need to address emissions associated with the delivery of natural gas, as well as reduce the production-related emissions of natural gas. While the production of natural gas represents a considerable source of emissions and is possibly one of the most significant focus areas to decarbonize, the natural gas delivery infrastructure will also significantly impact the pace of decarbonization of the natural gas industry. The decarbonization of transmission and distribution segments will be achieved with expeditious replacement of aging infrastructure materials and improvements to leak detection methodologies. Net-zero planning of the natural gas industry will require the substantial mitigation of fugitive emissions at each of the infrastructure segments.

The US natural gas pipeline system, supported by extensive underground storage facilities, plays a vital role in meeting the country’s energy demands. With its inter-seasonal storage capacity, integration of above and below-ground storage, and high deliverability, the system provides a reliable and resilient energy supply. As the US moves towards net-zero targets, investing in the natural gas pipeline system by replacing aging infrastructure, regulating methane leaks, and prioritizing emission reduction efforts will continue to be important for ensuring a successful energy transition. Also, by leveraging this existing infrastructure, the country can pursue decarbonization pathways as its significant transport and storage capabilities offer a unique opportunity for integrating renewable and low-carbon gases into the energy mix. The following sections of the paper will explore the potential of the US natural gas infrastructure system in facilitating decarbonization.

## Energy Efficiency

Natural gas utilities have made extensive strides to improve energy efficiency across the natural gas value chain. In 2019, natural gas utilities invested roughly 1.57 billion dollars towards energy efficiency programs, which increased by 20% from the previous year[30]. Natural gas energy efficiency investments were mostly concentrated on residential and low-income end users in 2019. Regions of the U.S. that experienced the greatest benefits of these programs in 2019 were the Northeast, followed by the South and the Midwest[17]. Despite lower reported investments in energy efficiency improvements to the commercial sector as compared to residential end users, the commercial sector experienced the greatest emission reductions in 2019 as a result of natural gas energy efficiency programs.

Major components of natural gas energy efficiency programs, as identified by the American Gas Association[31] include:

- Reducing Natural Gas Supply and Infrastructure Costs
- Promotion of Energy Conservation / Direct Impacts to Energy Savings
- Improvement of Safety and Comfort Benefits to Low-Income Customers
- Reducing Greenhouse Gas Emissions / Direct Impact on Avoided Emissions

Utilities have approached energy efficiency by incentivizing end users to install natural gas equipment into their homes and replacing the less efficient old natural gas equipment. Additionally, natural gas utilities have encouraged end users to convert other fuels such as propane, to natural gas. The majority of investments toward energy efficiency programs were reportedly associated with customer incentives in the form of rebates, loans, and other financial incentives. These energy efficiency efforts not only target the reduction of greenhouse gas emissions but also intend to improve the resiliency of existing infrastructure. Continued investments in energy efficiency programs are an essential step towards effective decarbonization of the natural gas value chain as they demonstrate the vital synergy between infrastructure development and environmental stewardship in the journey toward a more sustainable energy future.

## Energy Justice and Equity

Energy justice refers to the affordable, accessible, and equitable participation in the energy system of all individuals regardless of race, nationality, income, or geographical location. Another key aspect of a just and equitable energy system is the fair distribution of benefits and potential pollution, noise, or health impacts from energy generation and transmission facilities for all stakeholders.[32] Modernizing the current natural gas system and leveraging infrastructure for a net-zero future both bring opportunities to improve the energy justice and equity of the nation's energy system.

The emissions associated with the current natural gas pipeline infrastructure represent an important inequity that system modernization can alleviate. The density of transmission pipeline

[30] American Gas Association, 2019. Natural Gas Efficiency Programs Report, Natural Gas Efficiency Program Funding and Impacts. Source

[31] American Gas Association, 2019. Natural Gas Efficiency Programs Report, Natural Gas Efficiency Program Planning and Evaluation. Source

[32] National Conference of State Legislatures. Energy Justice and the Energy Transition. 2022. Source.

infrastructure has been found to correlate with increasing county-level social vulnerability[33] while increasing distribution pipeline leak density correlates to an increasing percentage of people of color and with decreasing median household income.[34] This means that low-income and minority communities are often burdened by an unfair portion of environmental and health impacts from natural gas infrastructure (for more information on the cost of environmental and health burdens from methane emissions, please see The Value of Avoided Emissions). Reducing infrastructure emissions by replacing leak-prone pipes and improving leak detection and repair is therefore crucial to achieving equity in the current gas system and is a paramount step in leveraging gas infrastructure in any decarbonization pathway.

Additional investments in infrastructure are needed, however, beyond pipeline replacements. Recent research has shown that community characteristics like population, average income, and employment status are negatively related to natural gas distribution investments, which can result in restricted access to natural gas in disadvantaged and rural communities.[35] Individuals living in such areas without an existing gas line must pay to have a new line installed from the gas supply and throughout their homes. This cost can be prohibitive, ranging from hundreds to thousands of dollars depending on the length of line and the size of the home. This represents another energy inequity, as households unable to afford the upfront cost to gain natural gas access for residential use must pay a higher monthly cost for alternatives like propane or electricity, which increases their energy burden (Table 1). Energy burden refers to the ratio of total energy spending to total income and can be over four times higher for people of color, older adults, and people with disabilities compared to the national average. In addition to its affordability, natural gas can also increase the reliability and resiliency of the grid as a dispatchable, on-demand source of power generation that can remain functional during disruptive events like power outages. This is significant for households that cannot afford to install residential renewable energy technologies or purchase portable generators for use during emergencies, as they are dependent on the reliability of the local power grid for all household energy needs. Strategically and mindfully investments in the current gas system can therefore decrease the financial burden of procuring reliable energy for vulnerable populations, increase the reliability of the power grid, and improve the equity and justice of the current and future energy system.

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[33] Emanuel, *et al.*, 2021. Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States. Source.

[34] Weller, *et al.*, 2022. Environmental Injustices of Leaks from Urban Natural Gas Distibution Systems: Patterns among and within 13 U.S. Metro Areas. Source.

[35] Muzeyyen Anil Senyel Kurkcuoglu. Analysis of the energy justice in natural gas distribution with Multiscale Geographically Weighted Regression (MGWR). December 2023. Source.

*Table 1: Average Unit Costs in Dollars per BTU of Five Residential Energy Sources for 2023 (Source: American Gas Association (AGA)[36])*

| Type of energy | Per million Btu [1] |
|---|---|
| Electricity | $46.19 |
| Natural Gas | 13.97 |
| No. 2 Heating Oil | 28.36 |
| Propane | 32.62 |
| Kerosene | 33.52 |

[36] American Gas Association. DOE Announces natural gas is 3.3 times more affordable than electricity. 2023. Source.

# Transitioning to Net Zero

Successful energy transition to net zero is understood to require multiple approaches. Natural gas operators across the US have multipronged net-zero commitments that consist of the deployment of alternative fuels (e.g., RNG, SNG, hydrogen), utilization of renewable energy, implementation of carbon capture, utilization, and storage, technology modernization and innovation (e.g., improved leak detection and repair programs), and replacement of aging infrastructure[37,38,39,40]. With alternative fuels, investments are being made in new RNG interconnections and pipeline extensions and securing procurement contracts. Several operators have successfully begun injecting RNG into their natural gas systems, while methanation pilot projects are taking place to evaluate future scale-up potential. Hydrogen blending pilots and research are being conducted to evaluate the feasibility of transporting hydrogen in existing natural gas pipelines to enable wide use. To increase the utilization of renewable energy, operators are evaluating powering facility operations with on-site installments or purchasing renewable energy to reduce Scope 2[41] emissions and utilizing renewable energy to produce alternative fuels. Power-to-gas (PtG) technologies are also being developed for long-term renewable energy storage. With technology modernization and innovation, operators are exploring options such as electrification of compression assets, deploying advanced leak detection tools, and expanding leakage surveys to reduce fugitive emissions. Lastly, with the replacement of aging incompatible infrastructure, operators are utilizing modern pipeline materials that are less susceptible to leakage. Overall, the value of the US natural gas infrastructure, with its extensive storage capabilities and efficient pipeline network, goes beyond the gases transported. By implementing regulations and developing technologies, the industry can move towards utilizing the existing pipeline system to transport and store renewable and low-carbon gases and continue diversifying the energy mix while gradually phasing out reliance on fossil fuels.

## Decarbonization Pathways of Natural Gas

There are several market-ready decarbonization solutions available to the present natural gas industry. The decarbonization pathways of the natural gas industry are inclusive of methods that either reduce fugitive emissions of natural gas infrastructure or lifecycle emissions of natural gas, with the production of emerging low-carbon fuels, also known as alternative fuels. Alternative fuels rely on renewable energy and bio-based feedstocks and can displace demand for fossil-based natural gas on a large scale. Scaling the deployment of alternative fuels will necessitate thoughtful consideration of regional-level feedstock availability, climate limiting factors, and energy demand profiles. Therefore, NZIP will be conducting 5 regional case studies (Gulf Coast,

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[37] Black Hills Energy Sustainability Report 2022. Source

[38] ConEdison Long-Range Plan: A Comprehensive View of Our Gas System through 2050. January 2022. Source

[39] SoCalGas. ASPIRE 2045: Sustainability and Climate Commitment to Net Zero. Source

[40] Nicor Gas. Building a Sustainable Future. 10 July 2023. Source

[41] EPA defines scope 2 emissions as “indirect greenhouse gas emissions associated with the purchase of electricity, steam, heat, or cooling.”

West Coast, Mountain, Midwest, East Coast) to assess existing systems and end-uses to provide investment and policy recommendations ideal for the specific region. The case studies will consider the level of investments, technology readiness, policy and regulatory landscape, and suitability of alternative fuels in the region. Decarbonization solutions identified to potentially significantly reduce emissions applicable to the natural gas industry discussed herein include:

- **Alternative Fuels**
  - Renewable Natural Gas (Distribution, Compressed and Liquified)
  - Synthetic Natural Gas (SNG)
  - Hydrogen
- **Direct Emissions Management**
  - Carbon capture, utilization, and storage
  - Improved emissions detection and quantification
  - Replacement of aging infrastructure

## Alternative Fuels

### Renewable Natural Gas (RNG)

RNG is pipeline quality natural gas which has been upgraded from one of the many sources of biogas. Commonly available sources of biogas involve anaerobic digestion either in landfills, or in anaerobic digesters with livestock manure, wastewater, or food waste. There are several factors which influence the propensity of biogas producers to produce RNG, such as cost, associated feedstocks, and location to a receiving natural gas pipeline. For instance, project scale may reduce the economic feasibility of RNG production and interconnection for a biogas producer. Despite hundreds of biogas projects in the US, not all projects are at the scale applicable to RNG upgrading and interconnection to natural gas infrastructure. Larger biogas projects may also opt out of producing RNG to instead produce on-site electricity due to onsite energy requirements, isolation from natural gas delivery infrastructure, or economic restrictions to upgrade to RNG. Location to natural gas infrastructure, as well as access to incentives to produce RNG are important indicators for RNG production from the many biogas producers in the United States.

### Technology Landscape

There are several digester designs utilized with agricultural digesters in the US. The most common digester designs include covered lagoons, complete mix, and plug flow digesters.[42] Covered lagoons are likely the most common agricultural digesters due to their lower capital costs and lower maintenance requirements. Additionally, manure lagoons on farms are easily retrofitted to covered lagoons for biogas collection. The deployment of any digester design is constrained by regional temperatures, which influences the prevalence of covered lagoon digesters in colder regions of the U.S. Complete mix digesters are operated above ground and plug flow digesters are partially below ground; yet both require additional heat to operate. Alternatively, covered lagoons are installed inground and can be operated at ambient

[42] U.S. EPA, 2023. AgSTAR Data and Trends. Source

temperatures. Anaerobic digesters can also offer a range of energy conversion times but are mostly recognized for passive, longer hydraulic residence times which yield high efficiencies.

Differences in gas quality occur with the various sources of RNG. The upgrading process to achieve RNG involves the removal of contaminants in biogas which do not comply with natural gas pipeline specifications, which can vary by operator. For instance, landfill gas and biogas from wastewater treatment facilities are affected by constituents such as siloxanes and hydrogen sulfide. Whereas agricultural digesters are not affected by siloxanes as their feedstocks are not impacted by consumer products that contain siloxanes. Additionally, due to the process and feedstock differences with SNG production, gas quality differences from RNG exist. Common constituents that are removed during the RNG upgrading process include $CO_2$, $O_2$, $N_2$, and VOCs. Additionally, biogas upgrading systems convert the biogas to a higher BTU content, agreeable with fossil natural gas. Several proven technologies exist in the biogas upgrading market to remove undesirable constituents in biogas to meet pipeline specifications.

There are several valuable end uses of RNG, which can offer further decarbonization, especially for natural gas-derived transportation fuels and industrial end users of natural gas. Compressed natural gas (CNG) is an alternative transportation fuel that is achieved with the compression of natural gas. Renewable compressed natural gas (R-CNG) is CNG which has been sourced from RNG rather than traditional fossil-based natural gas. The process of converting RNG to CNG involves compressor infrastructure, as well as the delivery infrastructure of the RNG if the compression cannot occur on-site at the RNG producer. Typically, R-CNG is achieved with an interconnection of an RNG producer to a compressor station. Like CNG, liquified natural gas (LNG) is also an alternative transportation fuel. Aside from the production route, renewable liquified natural gas (R-LNG) follows the same infrastructure requirements as fossil-fuel-derived LNG. LNG is produced through the cooling of natural gas into a liquid state. In order to achieve R-LNG, biogas must be upgraded to RNG standards, which is then transported to dedicated facilities to produce the liquefied, chemical equivalent of pipeline natural gas. Depending on end-use, R-LNG gas quality specifications may be more stringent than RNG, which requires more cost-intensive upgrading processes. Dedicated infrastructure for LNG and CNG requires specialized storage as compared to traditional natural gas, which is the case for renewable forms of LNG and CNG as well.

The U.S. LNG markets are more concentrated towards exports rather than for domestic end-use. LNG exports are transported via LNG terminals in connection with natural gas delivery pipelines. While CNG is mainly purposed for commercial transportation, LNG is more associated with industrial transportation use, such as rail, highway, and waterway vehicle fuel. There are three types of facilities associated with traditional LNG production: peak shaving plants, satellite plants, and transportation fuel plants. Peak shaving plants offset differences between the demand and supply of natural gas pipelines by storing natural gas. Satellite LNG plants, which are also referred to as regasification plants, rather store and convert LNG back to pipeline natural gas to match fluctuating demands in the natural gas systems. Thirdly, LNG is also associated with transportation fuel plants which represent a much smaller occurrence and are purposed for more industrial transportation. Conversion of LNG facilities to accept higher quantities of RNG will depend on the available supply of RNG and local fluctuations in natural gas demand. Peak shaving plants and satellite LNG plants can support the flexible use of R-LNG to match fluctuations in the energy demand of pipeline natural gas. Some instances of LNG storage result in conversion to electricity for onsite use, which can particularly support markets that cannot access traditional natural gas pipeline networks. However, R-LNG is likely not purposed for future electricity generation due to the specialized production requirements.

### Current Deployment and Initiatives

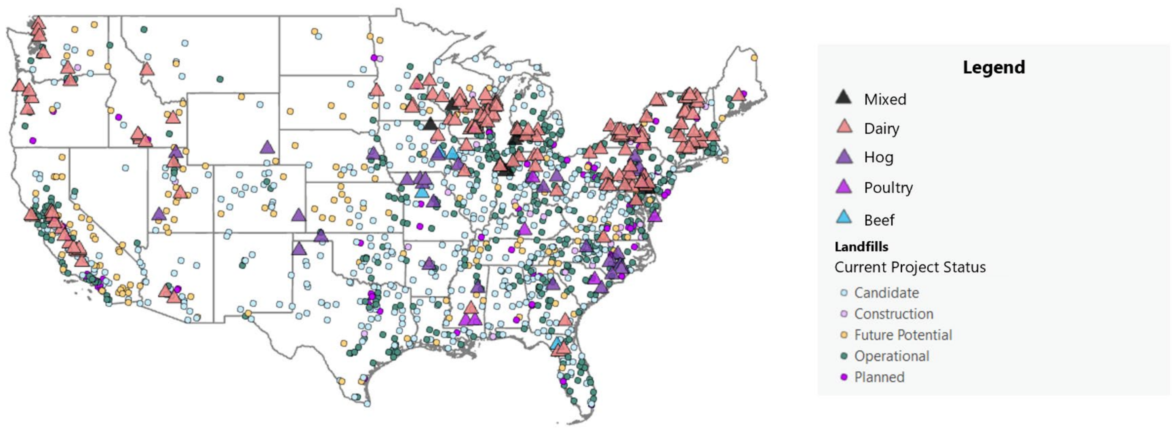


*Figure 15: Biogas Generators from Agriculture, Landfills (Source: EPA Agstar, EPA LMOP)*[16, 26]

The biogas market is the most prevalent renewable gaseous fuel in the US. The greatest biogas generation is associated with landfill gas collection systems. An estimated 232 billion cubic feet of landfill gas was collected at 311 landfills in 2021.[43] Biogas generation at landfills is dependent on the organic waste profile evolution and best applies to less mature municipal solid waste landfills. Agricultural digesters are another common source of biogas production. In 2022, there were 322 operational agricultural digesters, as well as 85 new digesters under construction (EPA AgStar)[22]. Figure 15 visualizes agricultural digesters, as well as current landfill gas projects in the United States. However, it is evident that many of the biogas producers in the U.S. do not produce renewable natural gas, as visualized in Figure 16. As of July 2023, there were 36 landfill gas projects identified to produce RNG, and 92 LFG projects were associated with renewable CNG end-use[26]. Similar to landfill gas projects, many agricultural digester facilities are recently associated with more CNG production rather than direct pipeline end use. As of Jan. 2023, 36 Ag digester projects were identified to produce pipeline gas, and 94 projects produced CNG[16]. The prevalence of renewable CNG production is greatly in part due to the availability of incentives such as through the EPA RFS and California LCFS programs.

[43] U.S. EIA, 2022. Biomass explained, Landfill gas and Biogas. Source

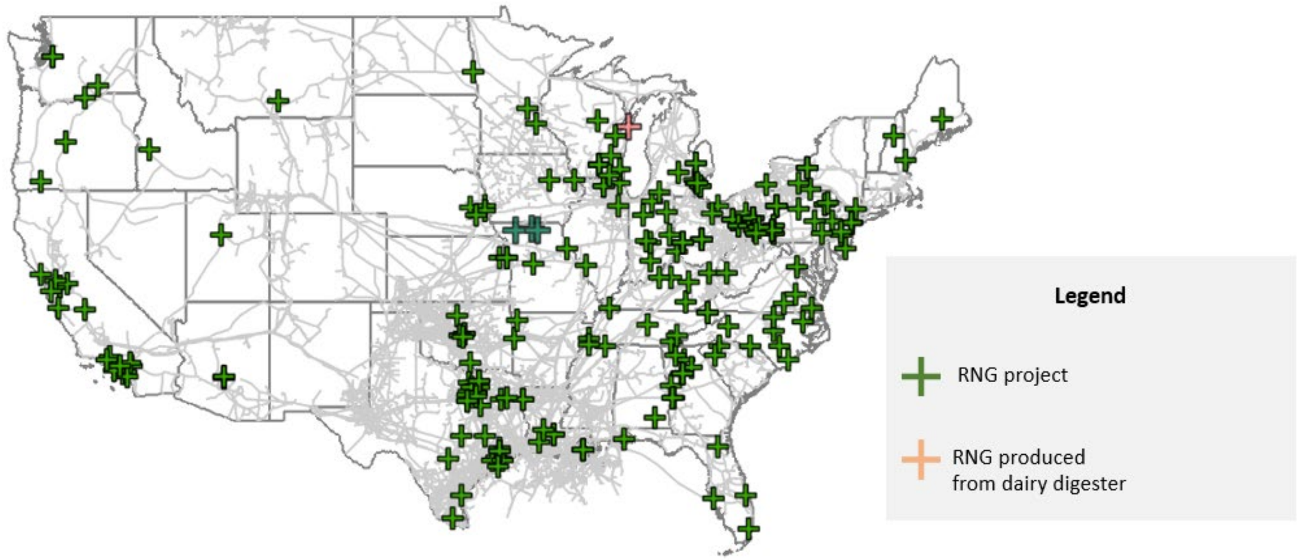


*Figure 16: RNG Projects in the United States (Sources: EPA AgStar, EPA LMOP)* [16, 26]

Wastewater treatment plants are also settings for anaerobic digestion. As of 2023, there were over 1,200 wastewater treatment plants which produced biogas with anaerobic digesters [44]. A greater proportion of biogas-producing wastewater treatment plants choose to convert the biogas to electricity, rather than upgrade to renewable natural gas. The propensity of biogas producers to upgrade biogas to RNG is generally linked to proximity to natural gas infrastructure, production scale, and onsite energy demands. Reported typical capital costs for gas compression and treatment is $6,200-$8,300 per standard cubic feet per minute (scfm) (i.e., $6.20 - $8.30 per MMBtu), and interconnection pipeline is $600,000 (less than 1 mile) and $1,000,000 per mile after th first mile[45]. As RNG interconnection cost is notably proportional to a producer's distance to a receiving natural gas pipeline, future RNG markets must be planned in agreement with the locations of existing natural gas infrastructure. Standalone food waste digesters are one of the least common types of anaerobic digesters. According to a 2018 national survey conducted by EPA, there were only 3 facilities associated with food waste digestion and RNG production[46]. These facilities were identified to be wastewater treatment plants that co-digest food waste to increase biogas yield. Co-digestion is not often encountered with RNG production as co-digestion can limit the available incentives to offset production costs. For instance, EPA RFS RINs do not include fuels from a combination of feedstocks, as calculated emissions reductions are not as straightforward.

However, the EPA Renewable Fuel Standard program RIN credits have been pivotal in the growth of several renewable fuel markets pertinent to the transportation sector. The most valued EPA RIN credits are categorized as D3 fuels, which are cellulosic biofuels. R-CNG and R-

[44] U.S. EPA, 2023. Types of Anaerobic Digesters. Source
[45] US Environmental Protection Agency, "Switch to Renewable Gas," 14 July 2022. Source
[46] U.S. EPA, 2023. Anaerobic Digestion Facilities Processing Food Waste in the United States. Source

LNG generate the most valuable RIN credits when associated with sources associated with biomass feedstocks, which can yield a minimum 60% reduction in lifecycle emissions compared to nonrenewable derived equivalents[47]. EPA reports that over two billion gallons of renewable CNG have been associated with EPA's Renewable Fuel Standard (RFS) renewable identification number (RIN) credit generation from 2020 to 2023[27]. Most of the RINs generated by renewable CNG and LNG in 2022 were D3 RINs, which yield the greatest value and are associated with cellulosic feedstocks. The CNG markets in the United States are notably greater than the LNG markets. In 2022, Renewable LNG RIN credits were associated with roughly 0.28 Bcf (28 million gallons), while renewable CNG was associated with over 0.24 Bcf (243 million gallons)[48]. However, the renewable LNG produced in the U.S. associated with EPA RFS RIN generation grew in volume by 28.85% from 2018 to 2022[27]. California has been a leading state in the incentivization of renewable CNG and LNG with the Low Carbon Fuel Standard program, which supports the production of renewable transportation fuels. In 2022, there were 26,712,553 LCFS credits generated by 520 entities, which are associated with 1 MT of carbon recovered for every credit generated. The LCFS program has been a major driver in the adoption of renewable CNG in California, which comprises 98% of the CNG utilized in the state as of 2021[49].

The Alternative Fuel Data Center has also geolocated alternative fueling stations for CNG and LNG.[50] Figure 17 visualizes the CNG and LNG fueling stations located in the United States[27].

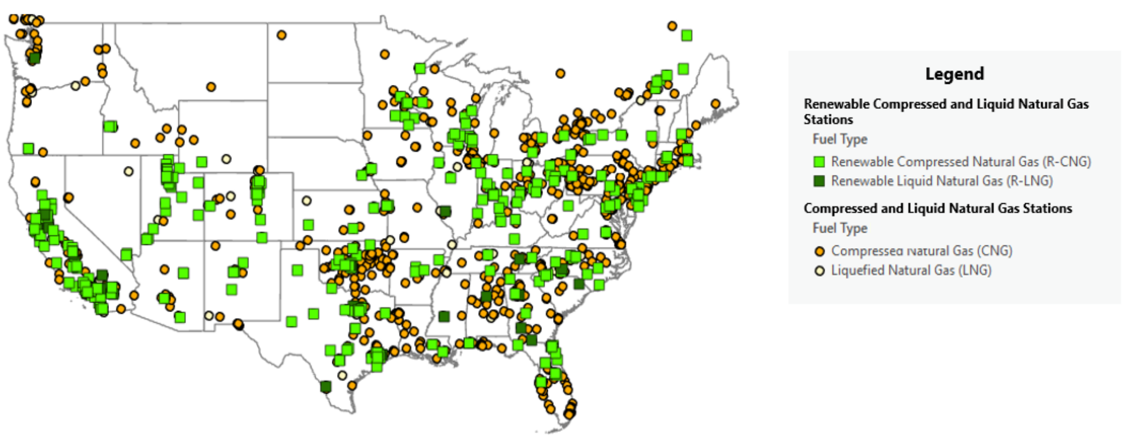


*Figure 17: CNG and LNG Fueling Stations in the United States (Source: EPA[29])*

[47] EPA, 2023. Renewable Fuel Annual Standards. Source
[48] U.S. EPA, 2023. RINs Generated Transactions. Source
[49] NGVAmerica, 2022. California Fleets Fueled With Bio-CNG Achieve Carbon-Negativity. Source
[50] Department of Energy, Energy Efficiency and Renewable Energy, 2023. Alternative Fuels Data Center. Source

As of 2022, there are approximately 160 LNG facilities in the United States[51]. Reporting of renewable LNG production in the United States is limited. Renewable LNG produced from landfill gas has been identified at two landfill gas sites in the U.S. as of 2023[26]. There are evidently more public CNG fueling stations than LNG fueling stations, which are both observed as generally overlapping in regions across the United States.

**Future Outlook**
RNG presents an opportunity to deliver to the high natural gas-demand sectors without requiring end-user retrofits or extensive delivery infrastructure changes. Studies suggest RNG has the potential to replace 5-20% of the total natural gas demand in the United States[52]. However, the near-term growth for RNG markets will likely target hard-to-decarbonize sectors. Strong interest in RNG is associated with the industrial and transportation sectors, with major companies pledging to increase RNG supplies in their systems over the next few decades. RNG has been economically feasible due to state and federal incentive programs such as the EPA Renewable Fuel Standard Program, as well as grant programs such as the USDA Rural Energy for America Program (REAP).

The availability of renewable compressed and liquified natural gas is heavily dependent on the supply of RNG. Renewable CNG and LNG fueling stations are positioned in many areas of the country along major transportation networks. As of 2023, R-CNG comprised over 72% of all CNG fueling stations in the U.S., while R-LNG represented nearly 45% of all LNG fueling stations (DOE Alternative Fuels Data Center)[29]. Both CNG and LNG are valuable fuels to the transportation sector, which is currently estimated to comprise 4% of total natural gas usage in the United States[53]. Incentives that have also supported other renewable transportation fuels will continue to increase the prevalence of R-CNG and R-LNG. Renewable CNG and LNG production have been incentivized through California's Low Carbon Fuel Credit Program (LCFS) and federal Alternative Fuel Excise Tax credits. The EPA Renewable Fuel Standard program also delivers credits to renewable CNG and LNG producers proportional to achieved emissions reductions, which are typically observed to reach 60% less when compared to landfill gas emissions[54].

Carbon intensities for the RNG pathways vary due to differences in utilized feedstocks, feedstock handling practices, selected biogas upgrading equipment efficiencies, and prevalence of flaring/venting which may result from operational disruptions. One of the key advantages of RNG is its ability to be seamlessly integrated into the existing natural gas infrastructure. By utilizing the existing gas pipelines, storage facilities, and distribution networks, the deployment of RNG can be rapidly scaled up and delivered to markets throughout the country, making it a viable solution for meeting decarbonization goals in the short to medium term. Even if some regions or states have minimal feedstocks for RNG, they can source RNG from other areas rich in

[51] PHMSA, 2023. Source
[52] Duke Energy, 2021. Evaluating Market Conditions for Renewable Natural Gas and Clean Hydrogen. Source
[53] U.S. EIA, 2023. Natural gas explained: Use of natural gas. Source
[54] EPA, 2022. Renewable Fuel Standard Lifecycle Greenhouse Gas Results. Source

RNG feedstocks, thereby decreasing energy costs for customers, just like they do today for fossil gas.

RNG can be stored and dispatched as needed, providing a reliable and flexible renewable energy option. This dispatchability addresses the intermittency challenges associated with certain renewable technologies, making RNG a valuable contributor to grid stability and energy reliability. Given the chemical compatibility and interchangeability between RNG and conventional natural gas, natural gas pipelines are well-suited for RNG transportation without significant modifications or alterations. RNG is especially valuable to sectors that are more difficult to abate emissions, such as the industrial, transportation, and power generation sectors.

## Synthetic Natural Gas (SNG)

Synthetic Natural Gas (SNG), also known as substitute natural gas, is a technology that converts various feedstocks, including biomass, coal, and waste, into a gas that closely resembles natural gas. SNG is considered an important component of the energy transition, as it offers a way to decarbonize the natural gas sector, repurpose waste feedstocks, and store renewable energy. SNG can be used for various applications, including electricity generation and heating. It also finds applications in industries and the residential sector, offering a versatile and sustainable energy source.

### Technology Landscape

The production of SNG involves several steps, including feedstock preparation, gasification, and gas cleaning. The resulting synthetic gas consists primarily of methane, which is the main component of natural gas. Key technologies and processes involved in SNG production include:

- **Gasification**: Gasification is a core process in SNG production. It involves thermally converting solid or liquid feedstocks into synthetic gas (syngas) containing hydrogen ($H_2$) and carbon monoxide (CO).
- **Electrolysis**: Chemical separation of water with electricity to produce $H_2$, $O_2$ which can be reacted with captured carbon which is typically achieved with renewable electricity
- **Methanation**: The syngas or electrolyzer product gas is then subjected to methanation, where $H_2$ and CO are reacted to produce methane ($CH_4$), the primary component of natural gas. This step is crucial for achieving gas quality similar to conventional natural gas.
- **Upgrading and Purification**: To meet natural gas pipeline quality standards, the SNG may require further upgrading and purification steps. These can include removing impurities like sulfur compounds and adjusting the energy content.

Gasification-based hydrogen and SNG production diversify fuel sources, reducing reliance on a single energy type. Existing natural gas infrastructure remains usable, with the potential for hydrogen blending into pipelines, enabling decarbonization without extensive system overhauls. Moreover, co-generation within integrated gasification combined cycle (IGCC) plants is advantageous. These plants can redirect syngas from electricity generation to produce SNG or hydrogen during off-peak periods. Notably, some facilities, like the Great Plains Synfuels Plant[55], have adapted to co-produce ammonia due to its economic viability, as predicted in a 2011 NETL study[56]. Refineries, too, benefit from gasification, converting low-value fuels like refinery bottoms, biomass, or waste into essential products. Hydrogen, crucial for petroleum refining, can be produced on-site, and surplus electricity offsets utility costs, while excess steam meets various facility needs.

The process by which SNG is produced from electrolysis is referred to as Power to Gas (PtG). This process typically starts with electrolysis, where electricity is used to split water (H2O) into hydrogen (H2) and oxygen (O2). Hydrogen generated through this process is then combined with biogenic or anthropogenic CO2, which can be sourced from various industrial processes or captured from the atmosphere to produce SNG through methanation. The methanation process can use catalysts combined with heat and pressure, or it can use methanogens (archaea) that accomplish this biologically. PtG can be a particularly valuable pathway for energy storage, particularly when generated from intermittent renewable sources like wind and solar. When renewable energy sources like wind turbines and solar panels generate excess electricity during periods of low demand or high renewable energy availability, this surplus energy can be used to produce SNG through processes like PtG. While PtG technology has been demonstrated at pilot scales, scaling up to meet the energy storage needs of entire regions or countries presents challenges in terms of technology readiness and investments.

SNG produced from the electrolysis process, also known as PtG, is not constrained by the same feedstock availability considerations as RNG or SNG from fossil fuel gasification. Some inherent benefits to both SNG pathways include potentially lower gas quality upgrading costs and some flexibility in whether SNG or hydrogen production will be prioritized. This process is also an enabler of CCUS as CO2 is captured and utilized throughout the process. The process can produce renewable hydrogen as well, which has its own set of applications, such as fuel cell vehicles and industrial processes. One of the primary advantages of SNG is its potential to reduce greenhouse gas emissions. By utilizing carbon-neutral or low-carbon feedstocks, such as biomass, coupled with CCS, SNG production can significantly mitigate the carbon footprint associated with traditional natural gas. Trading heavy fuel oil with SNG produced from a PtG reactor that utilizes captured carbon can approach 100% emissions reduction along the value chain[57]. While SNG can be produced from carbon-neutral feedstocks, the overall carbon footprint depends on the source of the feedstock and the production process.

**Current Deployment and Initiatives**

SNG production from converted coal plants has been historically of growing interest. Coal plants are often situated in prime locations across the U.S. and can further integrate with the natural gas delivery infrastructure. As of 2022, 225 coal-fired plants were operating in the United

[55] The Great Plains Synfuels Plant (GPSP) in Beulah, North Dakota has been in operation producing synthetic natural gas (SNG) from lignite coal for 25 years and remains the only coal-to-SNG facility in the United States. (Source)

[56] https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/hydrogen-commercial

[57] Man Energy Solutions, 2022. SNG- A climate-neutral fuel for the future. Source

States[58]. Only one example exists of a coal-to-SNG plant in the continental U.S., which is the North Dakota Great Plains Synfuels Plant. The Great Plains Synfuels Plant provides SNG to end users via pipeline interconnection[59] and produced roughly 51,779 MMscf of SNG in 2021[60]. SNG is also produced in Hawaii and was associated with 261 MMscf of SNG in 2021. The Hawai'i Gas owned facility in Oahu, Hawaii utilizes liquid petroleum fuel naphtha as the feedstock[61]. Given the lack of existing natural gas reserves in Hawaii, alternative natural gas production pathways such as SNG or RNG are necessary to meet the natural gas demands. Oahu presently has roughly 1100 miles of natural gas pipelines that deliver RNG, SNG, 15% Hydrogen, and LNG[43]. These two facilities represent the entirety of reported SNG production in the United States in 2022.

Several recently initiated efforts aim to validate the technical and economic feasibility of large-scale SNG production from renewable sources. Each project contributes to the broader goal of integrating low-carbon gases into the natural gas infrastructure and reducing carbon emissions.

TotalEnergies, in partnership with the Belgian start-up Tree Energy Solutions (TES), has unveiled intentions to co-develop a SNG facility in the United States[62]. This innovative (e-NG) plant will employ renewable hydrogen, generated by a 1 GW electrolyzer powered by 2 GW of wind and solar energy via long-term power purchase agreements, and carbon dioxide to manufacture a SNG, suitable for combustion as fuel. The $CO_2$ utilized in the e-NG process will be recycled from customer-operated carbon capture facilities to collect $CO_2$ at the point of emission[63]. Anticipated outcomes for the project include an annual production capacity of 100,000 to 200,000 metric tonnes of SNG. The project's final investment decision is scheduled for 2024, pending approvals and evaluations.

In the initial phase of its trial, Tokyo Gas has installed Hitachi Zosen's methanation device at its research center near Tokyo to produce 12.5 normal cubic meters per hour ($Nm^3/h$) of synthetic methane[64]. This SNG is generated from externally sourced hydrogen and CO2. Tokyo Gas plans to further enhance its production process by installing a water electrolysis device from Britain's ITM Power and using renewable-based hydrogen for synthetic methane production. Additionally, they intend to incorporate CO2 emissions captured from nearby factories or their customers. Tokyo Gas aims to replace approximately 1% of its city gas volume with synthetic methane by 2030. In the late 2020s, they plan to scale up production to reach 400 $Nm^3/h$, with an overseas demonstration in 2030 targeting 20,000 $Nm^3/h$.

In a pilot operation in Sempigny, France[65], synthetic methane injection was successfully conducted at the catalytic methanization unit. This unit is co-managed by pioneering farmers in

[58] Statista, 2022. Number of coal power plants by country. Source
[59] National Energy Research Laboratory, 2023. 7.5.1.Great Plains Synfuels Plant. Source
[60] EIA, 2023. U.S. Supplemental Supplies of Natural Gas. Source
[61] Hawai'i Gas, 2023. Energy and Decarbonization. Source
[62] United States: TotalEnergies and TES Join Forces to Develop a Large-Scale SNG Production Unit Source
[63] TES, 2023. We cap-ture and recycle $CO_2$. Source
[64] Tokyo Gas begins synthetic methane trial using green hydrogen Source
[65] First injection of synthetic methane into the French gas distribution network Source

green gas production, and the demonstrator achieved this milestone by producing SNG using CO2 directly captured on the biomethane production site and hydrogen generated through electrolysis. This achievement confirms the feasibility of injecting SNG into the gas distribution network. Synthetic methane production has significant potential in France, with up to 50 TWh of renewable gas production projected by 2050. However, for this sector to thrive, it requires a clear regulatory framework and support mechanisms to facilitate its industrialization.

Electrochaea's Biocat biomethanation plant is one example of a PtG process that leverages renewable electricity and $CO_2$ to produce methane. The Biocat methanation process requires a biocatalyst to convert the produced hydrogen and $CO_2$ to methane and water vapor. The Biocat plant is set to convert 5,700 mt of $CO_2$ a year and thus produce 2.8m $Nm^3$ synthetic methane[66]. The PtG process importantly repurposes captured $CO_2$, thus reducing otherwise fugitive emissions. Electrochaea has received financial support from the European Innovation Council to develop commercial designs for modular plants with capacities from 10 to 75 Mwe[10].

**Future Outlook**

The compatibility of SNG with existing natural gas infrastructure is generally feasible but requires certain considerations and modifications. SNG is chemically similar to natural gas, primarily composed of methane. This similarity in composition means that SNG can generally be transported through the same pipelines and distribution networks used for natural gas. However, natural gas pipelines have specific quality standards that must be met to ensure safe and efficient transportation. Therefore, SNG produced from various sources, such as biomass gasification or PtG processes, may need treatment and purification to meet these quality standards. This can involve removing impurities and adjusting the energy content of the gas.

Furthermore, natural gas pipelines operate at varying pressures depending on the region and the specific application. SNG may need to be compressed or pressurized to match the pressure requirements of the existing infrastructure. Compression stations and facilities can be integrated into the transportation system to achieve this. Hence, depending on the specific characteristics of the SNG and the natural gas infrastructure, some modifications to pipelines and distribution systems may be necessary to ensure smooth transportation and distribution. Nonetheless, in many cases, SNG is compatible with the appliances and equipment designed for natural gas use. This is especially true if the SNG meets the required quality standards. Homes, businesses, and industrial facilities that use natural gas for heating, cooking, or industrial processes can often use SNG without major modifications to their equipment.

SNG can similarly be stored in existing natural gas infrastructure, making it a valuable option for energy storage, especially when generated from intermittent renewable sources like wind and solar. Repurposing existing natural gas infrastructure for SNG storage can be cost-effective compared to building entirely new energy storage systems from scratch. This reutilization minimizes the need for additional capital investment in energy storage infrastructure. While the integrated PtG process holds immense promise, there are challenges to overcome, including the cost of electrolysis, the sourcing of $CO_2$, and the need for a well-developed infrastructure for hydrogen and SNG distribution. Incorporation of $CO_2$ into the SNG process can be achieved

[66] Electrochaea, 2023. [Electrochaea GmbH - Power-to-Gas Energy Storage | Technology. Source]

through carbon capture and repurposing of a power plant's exhaust emissions. Furthermore, the efficiency of the PtG process, particularly electrolysis and methanation, needs improvement. Efficiency losses during these conversion steps can reduce the overall energy storage effectiveness. Research and development efforts are ongoing to enhance the energy efficiency of these processes.

Several countries, such as Japan, China, and Germany, have already begun deploying SNG technology on a larger scale. Governments and industry players are investing heavily in research and development to advance SNG technologies. This includes improving the efficiency of gasification processes and expanding the use of renewable feedstocks. Reducing costs is crucial to making coal-to-SNG processes economically competitive. This challenge is exacerbated by fluctuating natural gas prices, which were significantly lower in 2020. Supportive policies and incentives, such as carbon pricing and emission reduction targets, are driving the adoption of SNG as part of a broader strategy to combat climate change.

SNG presents a versatile market opportunity, applicable wherever natural gas is used, including potential hydrogen-SNG blends. Industrial settings stand out, where on-site gasification can yield SNG and even electricity, facilitating the transition from natural gas to solid fuels. In 2022[67], the U.S. industry consumed 26% of the nation's natural gas supply, underlining the significance of industrial applications. In essence, while SNG offers broad applications and advantages, overcoming cost, reliability, and transport challenges is pivotal for its widespread adoption. Collaboration among industry, regulatory bodies, and technological advancements will be key to a successful transition to these sustainable energy sources.

## Hydrogen

Hydrogen is a versatile energy carrier and has been utilized as a fuel since the early 19th century. Over the last several years, hydrogen has been gaining momentum as a promising energy carrier for decarbonization. With its end-use versatility, hydrogen has the potential to support decarbonization of the transportation, power generation, industrial, residential, and commercial sectors.

### Technology Landscape

Common and promising methods to produce hydrogen include electrolysis, natural gas reforming, partial oxidation, biomass gasification, and methane pyrolysis.

<u>Electrolysis</u>

Electrolysis is the process of using electricity to split water into hydrogen and oxygen. An electrolyzer is formed by a cathode, an anode, and an electrolyte. The electrolyte is selective towards the ions that it can conduct in order to keep reactions of both sides of the electrolytic cell balanced. In 2022, less than 1% of hydrogen produced in the US was via electrolysis. There are four types of electrolysis technologies. Proton Exchange Membrane (PEM) electrolysis utilizes a solid specialty plastic material as the electrolyte and is efficient in producing high-purity hydrogen with fast response times, making it suitable for dynamic energy storage and grid balancing applications. However, it is expensive due to the use of precious metals and

[67] EIA, 2023. Natural gas explained. Source.

requires high-purity water. Alkaline electrolysis, the oldest technology, uses potassium or sodium hydroxide as the electrolyte, producing high-purity hydrogen with a longer lifespan but slower response times compared to PEM. Solid Oxide Electrolysis Cell (SOEC) operates at high temperatures using a ceramic electrolyte, offering high efficiency and the potential for co-electrolysis of water and carbon dioxide but faces challenges such as component failure and degradation at high temperatures[68]. It is a promising developing technology for large-scale electrolysis systems. Finally, Anion Exchange Membrane (AEM) electrolysis uses an alkaline solution as the electrolyte, and shows promise for cost-effective scaling; ongoing research efforts are focused on improving its efficiency, durability, and cost-effectiveness.

*Energy Sources Used for Electrolytic Hydrogen*
Electrolytic hydrogen has the potential to leverage renewable energy sources and nuclear energy to produce zero-carbon hydrogen. Utilizing renewable energy sources, such as solar and wind, can serve as a long-term energy storage method for electricity that is otherwise curtailed due to supply exceeding demand.[69] Compared to batteries that have hours of storage, hydrogen essentially has an indefinite storage capability.

Utilizing nuclear energy is another pathway to consider for zero-carbon hydrogen production as nuclear power plants do not result in combustion byproducts. Nuclear energy makes up 51.6% of carbon-free electricity and approximately 18.9% of overall electricity generated in the US.[70] As of August 1, 2023, there are 93 reactors at 54 nuclear power plants in 28 states.[71]

Natural Gas Reforming - Steam Methane and Autothermal Reforming
Natural gas reforming is currently the most common method to produce hydrogen. In 2022, approximately 95% of the hydrogen produced in the US was from natural gas reforming (steam methane reforming and autothermal reforming) without carbon capture and storage (CCS) technology, and less than 5% of the hydrogen produced utilized CCS technology.[72]

Steam methane reforming (SMR) involves using high-pressure steam in a reaction with methane to form hydrogen, carbon monoxide, and carbon dioxide ($CO_2$). In the final process, called pressure swing adsorption, $CO_2$ and other impurities are removed to yield high-purity hydrogen. SMR is energy-intensive, requiring high temperatures (700 to 1000°C) for the process. SMR

[68] Kamkeng, Ariane D.N.; Wang, Meihong. Long-term Performance Prediction of Solid Oxide Electrolysis Cell (SOEC) for CO2/H2O Co-electrolysis Considering Structural Degradation through Modelling and Simulation.
[69] As an example: in April 2023, California Independent System Operator (CAISO) curtailed 702,883 megawatthours of wind and solar electricity, which is equivalent to energy from approximately 413,504 barrels of oil. Source
[70] Nuclear Energy Institute. Nuclear Energy: Just the Facts. June 2021. Source
[71] U.S. EIA. Nuclear explained. 26 October 2023. Source
[72] U.S. National Clean Hydrogen Strategy and Roadmap. 2023. Source

produces a significant amount of $CO_2$, approximately 9 to 14 kilograms of $CO_2$ per kilogram of hydrogen depending on the energy source used and the process efficiency.[73]

Autothermal reforming (ATR) uses oxygen and carbon dioxide or steam in a reaction with methane to form a synthesis gas, which is a mixture of hydrogen and carbon monoxide that also contains inert compounds such as argon, methane, nitrogen, and $CO_2$. The hydrogen is then separated from the synthesis gas via absorption or adsorption. Unlike an SMR process, the reaction heat is in the reaction vessel and no external furnace is required. In the reforming reactor, methane is partially oxidized by oxygen, and the generated heat drives the endothermic reforming reaction.

To reduce emissions from steam methane and autothermal reforming, CCS technology can be used. This type of lower-emissions hydrogen is commonly known as "blue hydrogen" as opposed to "grey hydrogen", which is produced by reforming natural gas without CCS. Since an ATR process has a higher concentration of $CO_2$, it would yield a higher carbon capture rate compared to an SMR process.[74] Another option to reduce production emissions is to utilize renewable natural gas (RNG), biogas, or biomass as feedstock combined with CCS technology. Depending on the RNG, biogas, or biomass source, the hydrogen produced can be zero or negative-carbon intensity. Without CCS, the utilization of RNG or biogas as feedstock for producing hydrogen can still result in low-carbon hydrogen. It is estimated that hydrogen production via biomass gasification (using poplar wood) would result in approximately 12% of the carbon intensity of an SMR process utilizing natural gas.[75]

Figure 18 compares the carbon intensities and projected unit costs of hydrogen produced from several production methods in the US. With tax credits, it is projected that blue hydrogen from SMR or ATR would have similar costs as electrolytic hydrogen produced using renewable and nuclear energy ($1.20/kg versus $1.60/kg) in 2030. Of the as-is production methods, hydrogen produced via electrolysis using renewable and nuclear energy sources would yield the lowest carbon intensity. However, if renewable feedstocks are used with reformation processes, it can significantly reduce the carbon intensity, comparable to electrolytic hydrogen from renewable and nuclear energy.

[73] Dagle, R., Dagle, V., Bearden, M., Holladay, J., Krause, T., Ahmed, S. An Overview of Natural Gas Conversion Technologies for Co-Production of Hydrogen and Value-Added Solid Carbon Products. November 2017. Source

[74] Gorski, Jan, Jutt, Tahra, Tam Wu, Karen. Carbon intensity of blue hydrogen production. August 2021. Source

[75] Based on calculations from GTI Energy's Hydrogen Production Emissions Calculator (HyPEC), which is based on the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model developed by Argonne National Laboratory. Assuming a 90% capture rate, estimated carbon intensities are 10.72 kg CO2e/kgH2 via SMR versus 1.27 CO2e/kgH2 with biomass gasification. The GREET model default inputs exclude infrastructure-related emissions and includes hydrogen transportation emissions, and hydrogen refueling compression emissions.

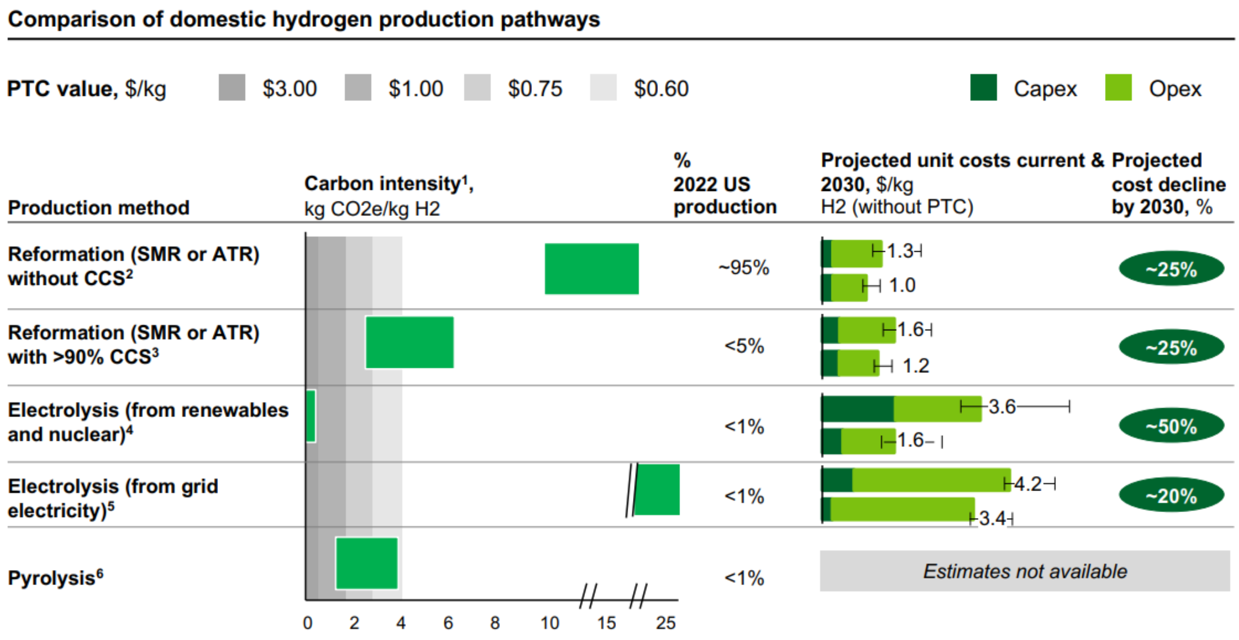


*Figure 18: Carbon intensity and projected costs comparison of domestic hydrogen production pathways (Source: DOE Pathways to Commercial Liftoff: Clean Hydrogen (March 2023)[70]*

Partial Oxidation

In a partial oxidation process, methane reacts with oxygen to form carbon monoxide and hydrogen. The carbon monoxide then reacts with water to produce $CO_2$ and more hydrogen. The partial oxidation process occurs faster than steam reforming and requires a smaller reactor. Like steam and autothermal reforming, utilizing RNG or biogas as feedstock and/or incorporating CCS technology would reduce $CO_2$ emissions and result in hydrogen that has low, zero, or negative carbon intensity.

Biomass Gasification

Biomass includes agricultural residues, forestry waste, organic municipal solid waste, and animal waste. Biomass gasification is a process that converts these materials at high temperatures (greater than 700°C) into carbon monoxide, hydrogen, and $CO_2$. Hydrogen is separated from the product using adsorbers or special membranes and then further purified.[76] If combined with CCS, the hydrogen produced can have a negative carbon intensity. Challenges with utilizing biomass include supply availability, management of byproducts, and resource quality that would require additional processing.

Methane Pyrolysis

Pyrolysis utilizes high temperatures (greater than 700°C) to break up methane into hydrogen and solid carbon. In 2022, pyrolysis made up less than 1% of US hydrogen production.[77] This method is a promising pathway for producing low-carbon hydrogen as there is no $CO_2$ byproduct. Similar to the other fossil-based hydrogen production methods, the utilization of

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[76] DOE. Hydrogen Production: Biomass Gasification. 10 July 2023. Source

[77] U.S. National Clean Hydrogen Strategy and Roadmap. 2023. Source

RNG or biogas as the methane source can yield low-carbon hydrogen. One challenge with methane pyrolysis is the energy input required for this high-temperature process. However, compared to steam methane reforming and electrolysis, pyrolysis has a lower specific energy demand (37.8 kJ/mol hydrogen compared to 63.3 kJ/mol hydrogen and 285.9 kJ/mol hydrogen[78], respectively). The production of carbon black with biomass-derived pyrolysis oil is being explored as an opportunity to offset the pyrolysis process costs[79].

**Current Deployment and Initiatives**

In the US, hydrogen is currently primarily used for industrial processes (e.g., ammonia and methanol production, petroleum refining, steelmaking, etc.). Other current uses include fuel cell electric vehicles (FCEVs), fuel cells for stationary and backup power, and forklifts.[80] Light-duty FCEVs are commercially available in California, while heavy-duty FCEVs are available for pilot projects. Figure 19 summarizes current US hydrogen use outside of industrial applications.

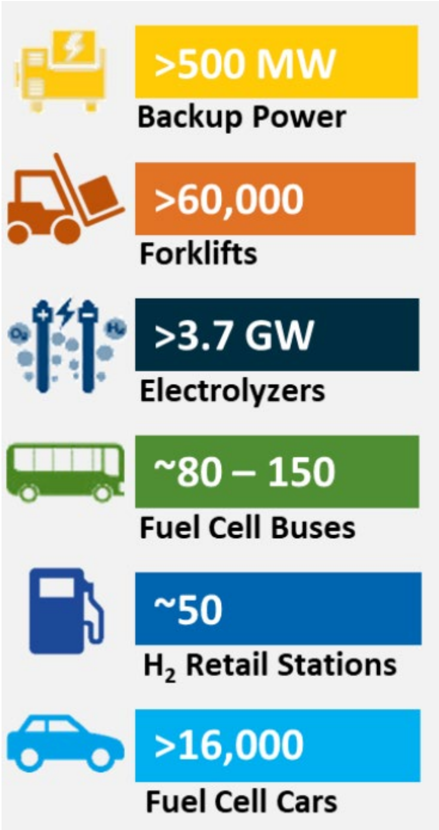


*Figure 19: Carbon intensity and projected costs comparison of domestic hydrogen production pathways (Source: DOE Pathways to Commercial Liftoff: Clean Hydrogen)*

[78] DVGW. Pyrolysis: Potential and possible applications of a climate-friendly hydrogen production. October 2022. Source

[79] Green Chemistry, 2018. Structure of carbon black continuously produced from biomass pyrolysis oil. Source

[80] U.S. National Clean Hydrogen Strategy and Roadmap. 2023. Source

As seen in Figure 20, many hydrogen projects are located in California while the majority of hydrogen pipelines are located in the Gulf Coast region.[49] Major expansion of hydrogen infrastructure across the US would be needed to increase the use of hydrogen, especially in the transportation sector.

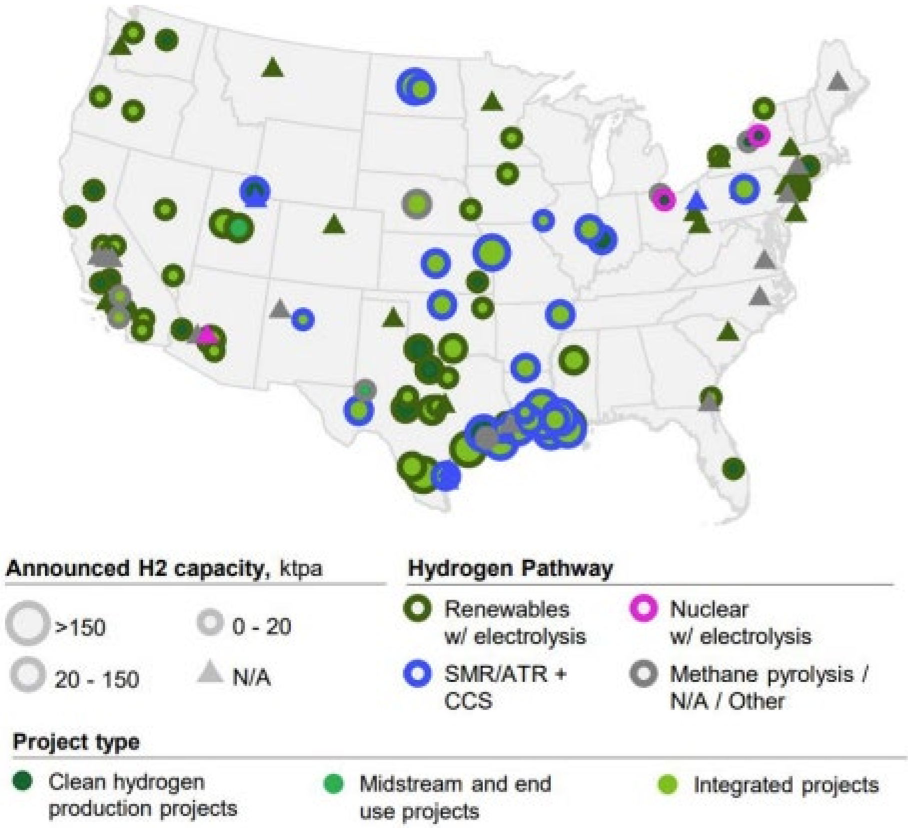


*Figure 20: Planned and installed hydrogen projects in the United States[81]*

Gas utilities are exploring blending hydrogen into existing pipeline infrastructure to reduce the carbon content in their gas supplies. Dominion Energy Utah, CenterPoint Energy, and New Jersey Resources have active hydrogen blending pilots to evaluate blending hydrogen into parts of their distribution systems. Other utilities[82] have announced plans to conduct similar pilots over the next few years. As utilities gain operational experience with hydrogen blending and new and updated procedures and standards are developed, it is anticipated that hydrogen blending will be more common, supporting wider use of hydrogen and reduction in delivery costs. Prior to the widespread use of existing gas infrastructure for hydrogen transport, there is a need to understand the operational impacts of hydrogen (e.g., compression, energy delivered, pipeline integrity management).

The ability to leverage existing geological storage facilities for hydrogen is another active area of research. One important effort is the Subsurface Hydrogen Assessment, Storage, and

[81] U.S. DOE, 2023. U.S. National Clean Hydrogen Strategy and Roadmap. Source
[82] Example utilities include Xcel Energy, SoCalGas, San Diego Gas & Electric, Pacific Gas & Electric, and Southwest Gas Corporation.

Technology Acceleration (SHASTA), which has the objective to assess the viability, safety, and reliability of storing hydrogen or hydrogen blends in underground formations.[83] Results are anticipated in 2024. An upcoming DOE funding opportunity[84] will fund a two-year project beginning in 2023 to further investigate high-volume, long-term subsurface hydrogen storage. Accomplishing widespread bulk storage of hydrogen using existing facilities would not only support a resilient energy system but also significantly reduce the cost of hydrogen if large amounts of hydrogen can be stored and then delivered via pipelines instead of trucking.

DOE's H2@Scale initiative, which launched in 2016, aims to advance hydrogen production, transport, storage, and use, through research, development, and demonstrations. DOE has issued Cooperative Research and Development Agreement (CRADA) Calls targeting production, infrastructure, grid integration, safety, codes, standards, and end uses.[85] One project is H2@Scale in Texas and Beyond, which involves a demonstration at the University of Texas at Austin that will produce electrolytic hydrogen using solar and wind power and renewable hydrogen using RNG. The hydrogen will supply a stationary fuel cell and a refueling station. A second part of this project is a feasibility study to scale up hydrogen production and use at the Port of Houston.[86] In October 2021, DOE announced approximately $8 million for nine projects to complement existing H2@Scale efforts and to support the Hydrogen Shot goal of reducing the cost of clean hydrogen to $1 per kilogram in one decade.[87] These projects cover topics such as integrated hydrogen energy system testing and validation, applied risk assessment and modeling, and next-generation sensor technologies.

The Bipartisan Infrastructure Law passed in November 2021 allocated $8 billion for a hydrogen hub program, which includes up to $7 billion to create six to ten regional clean hydrogen hubs in the US.[88] These Regional Clean Hydrogen Hubs will establish networks to promote the production, delivery, storage, and use of clean hydrogen. The intent is for the hubs to accelerate the advancement of hydrogen technologies and to scale up hydrogen infrastructure and use around the US.

Figure 21 shows the 7 hubs that were selected for federal funding. The following provides a brief description of each of the hubs:[89]

- **Appalachian Hydrogen Hub (ARCH2):** Covering West Virginia, Ohio, and Pennsylvania, this hub will involve developing hydrogen pipelines, hydrogen refueling stations, and permanent CO2 storage. The intent is to remove approximately 9 million metric tons of CO2 per year.

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[83] SHASTA Subsurface Hydrogen Assessment, Storage, and Technology Acceleration. 10 July 2023. Source
[84] Funding Opportunity Announcement 2400, Area of Interest 16. Source
[85] DOE. H2@Scale. Source
[86] The University of Texas at Austin. H2@Scale Project Launched in Texas. 15 September 2020. Source
[87] DOE. DOE Announces Nearly $8 Million for National Laboratory H2@Scale Projects to Help Reach Hydrogen Shot Goals. 6 October 2021. Source
[88] DOE. Regional Clean Hydrogen Hubs. 10 July 2023. Source
[89] DOE. Regional Clean Hydrogen Hubs Selections for Award Negotiations. 26 October 2023. Source

- **California Hydrogen Hub (ARCHES):** This hub will produce hydrogen utilizing renewable energy and biomass and will focus on decarbonizing public transportation, heavy-duty transportation, port operations, and power generation. The intent is to remove approximately 2 million metric tons of $CO_2$ per year.
- **Gulf Coast Hydrogen Hub (HyVelocity):** Centered in the Houston area, this hub will produce hydrogen utilizing renewables-powered electrolysis and natural gas with carbon capture and develop salt cavern hydrogen storage, open access hydrogen pipeline, and hydrogen refueling stations. The intent is to remove approximately 7 million metric tons of $CO_2$ per year.
- **Heartland Hydrogen Hub (HH2H):** Covering Minnesota, North Dakota, and South Dakota, this hub will help decarbonize fertilizer production and power generation and decrease clean hydrogen costs in the region. The intent is to remove approximately 1 million metric tons of $CO_2$ per year.
- **Mid-Atlantic Hydrogen Hub (MACH2):** Covering Pennsylvania, Delaware, and New Jersey, this hub will produce hydrogen using renewables and nuclear electricity. The hydrogen will be used to help decarbonize heavy transportation, manufacturing and industrial processes, and combined heat and power. The intent is to remove approximately 1 million metric tons of $CO_2$ per year.
- **Midwest Hydrogen Hub (MachH2):** Covering Illinois, Indiana, and Michigan, this hub will help decarbonize steel and glass production, power generation, refining, and heavy-duty transportation. The hub will utilize renewable energy, natural gas, and nuclear energy to produce hydrogen. The intent is to remove approximately 3.9 million metric tons of $CO_2$ per year.
- **Pacific Northwest Hydrogen Hub:** Covering Washington, Oregon, and Montana, this hub will help decarbonize heavy transportation, fertilizer production, power generation, refineries, and seaports. The intent is to remove approximately 1.7 million metric tons of $CO_2$ per year.


*Figure 21: Hydrogen hubs selected for federal funding (Source: Office of Clean Energy Demonstrations)*

In July 2023, the federal government announced a demand-side initiative to complement the Regional Clean Hydrogen Hubs, by providing revenue certainty for hydrogen producers.[90] Potential incentives are production tax credits and funding of research and development and demonstration projects to lower the cost of hydrogen production technology and to reduce the risk of market failures.[91] The intent is for these incentives to support the early commercial viability of the hydrogen hubs by helping producers attract private investments. The IRA 45V incentives also complement the Regional Clean Hydrogen Hubs by offering hydrogen producers revenue certainty. These incentives encompass production tax credits and funding for research, development, and demonstration projects aimed at reducing hydrogen production costs and market risks. The IRA also allows certain hydrogen projects to qualify for an investment tax credit under Section 48 of the Internal Revenue Code, which allows for specific clean hydrogen production facilities to be treated as energy property. These investments are strategically targeted at lowering the cost of hydrogen production technology and mitigating the risks associated with potential market failures. The overarching goal is to bolster the early commercial viability of the hydrogen hubs by making them more attractive to private investors.

In the meantime, several companies are in the process of scaling up clean hydrogen production. Some of these projects are SGH2's 11,000-kilogram-per-day green hydrogen facility in

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[90] DOE. Biden-Harris Administration to Jumpstart Clean Hydrogen Economy with New Initiative to Provide Market Certainty And Unlock Private Investment. 5 July 2023. Source

[91] The White House. The Economics of Demand-Side Support for the Department of Energy's Clean Hydrogen Hubs. 5 July 2023. Source

California,[92] Air Products' 35-metric-ton-per-day green hydrogen plant in New York (2026 start-up)[93], and the largest US green hydrogen plant (over 200 metric tons per day) in Texas that has an anticipated 2027 start-up[94].

**Future Outlook**

Hydrogen's versatility across end-use sectors makes it a promising pathway to achieve net zero emissions. Hydrogen has the potential to decarbonize hard-to-electrify applications. With transportation, hydrogen fuel cells can provide the long-range and rapid refueling required for heavy-duty vehicles to avoid major disruption of supply chains. Hydrogen-powered trains have the potential to replace diesel locomotives, while hydrogen-powered ships, ferries, drones, and unmanned aerial vehicles could decarbonize maritime and aviation applications. In the power generation sector, hydrogen fuel cells can support microgrids and provide stationery and backup power. Hydrogen can also fuel gas turbines to generate electricity and reduce or replace the use of natural gas for power plants. Existing industrial processes that use hydrogen (e.g., chemicals manufacturing, petroleum refining) can reduce emissions by utilizing clean hydrogen as opposed to fossil-based hydrogen.

Cost is currently a major barrier to large-scale adoption. With federal government loans, grants, and incentives, the cost of hydrogen can be significantly reduced to support the wider adoption of this fuel. There is also the opportunity to leverage existing gas infrastructure to lower transport and storage costs; however, there is a need for further research and investments to determine the suitability of transporting hydrogen in existing infrastructure and to repurpose infrastructure deemed suitable. The US National Clean Hydrogen Strategy and Roadmap published in June 2023 outlines three strategies to enable the wide adoption of clean hydrogen[95] in the country. The first strategy is to target high-impact uses of clean hydrogen, which are industrial applications (e.g., chemicals manufacturing, steelmaking, high-temperature heat), transportation (e.g., medium and heavy-duty, maritime, aviation, rail), and power (e.g., backup power, stationary power, energy storage, electricity generation). The goal is to achieve 5 MMT/year of clean hydrogen by 2030.[96]

The second strategy is to reduce the cost of clean hydrogen, with a goal of $2/kg by 2026 and $1/kg by 2031. The Hydrogen Shot initiative intends to promote investments and commercialization of low-carbon hydrogen production through grants, loans, and tax incentives. To achieve $1/kg using electrolyzers, electricity and capital costs will need to be significantly reduced along with improvements in efficiency and durability and increased utilization. Assuming a 90% electrolyzer efficiency, it is estimated that energy costs and capital costs would need to be reduced to $20/MWh and $150/kW, respectively, to achieve the $1/kg Hydrogen

[92] SGH2. Projects. 24 October 2023. Source
[93] Air Products. New York Green Hydrogen Facility. 10 July 2023. Source
[94] Office of the Texas Governor. Governor Abbott Celebrates Construction Of Nation's Largest Green Hydrogen Facility In Texas. 8 December 2022. Source
[95] The Bipartisan Infrastructure Law requires the Department of Energy (DOE) to define clean hydrogen as having a carbon intensity of less than 2 kilograms (kg) CO2e produced at the production site per kg of hydrogen produced.
[96] U.S. National Clean Hydrogen Strategy and Roadmap. 2023. Source

Shot goal.[97] Hydrogen production using SMR with CCS currently costs approximately 55% more compared to SMR alone.[98] Costs can be reduced with improved integration with $CO_2$/hydrogen separation, utilization of advanced catalysts and more efficient membranes, and lower $CO_2$ transport and storage costs. In addition to production costs, other factors that contribute to the overall cost of hydrogen are delivery, storage, and dispensing. Gaseous tube trailers, liquid tankers, pipelines, and chemical hydrogen carriers are the current various delivery methods. Pipeline delivery would be the least-cost delivery method. Therefore, capital costs can be significantly reduced if existing pipeline infrastructure can be leveraged to transport hydrogen. Chemical hydrogen carriers are ideal for long-distance delivery and export; however, more research is needed to increase capacity and efficiency. For onboard storage and dispensing, research is needed to reduce the cost of materials used for vessels and to improve the reliability and capacity of fueling equipment (e.g., compressor, chiller, storage, dispenser) to support capital and operating cost reductions.

The third strategy is to scale up regional clean hydrogen supplies and demand.[99] Production, storage, and end-use potentials vary by region. The intent is for Regional Clean Hydrogen Hubs to leverage the unique regional infrastructure and energy source potentials to optimize large-scale production and use of clean hydrogen.

The US National Clean Hydrogen Strategy anticipates clean hydrogen to be developed in three waves (Figure 22, giving priority to material handling equipment, refineries, clean ammonia production, heavy-duty trucks, and transit buses. These existing applications are hard to electrify and can be located by large-scale hydrogen production (e.g., industrial clusters). Material handling equipment (e.g., forklifts) used at ports, warehouses, and other industrial sites, have high utilization require fast refueling, and would have predictable refueling locations. Refineries and ammonia plants already use large amounts of hydrogen, and replacing fossil-based hydrogen with clean hydrogen can significantly reduce emissions from these processes. Heavy-duty trucks and machinery and transit buses are energy-intensive and would also require fast refueling, making them attractive use cases. By prioritizing these end-uses in the first wave, it is anticipated that the infrastructure built can be leveraged for the end-uses in the second and third waves. For example, in the second wave, medium-duty hydrogen fuel cell trucks can utilize infrastructure that will have been built for heavy-duty hydrogen fuel cell trucks.

[97] Ibid.

[98] National Energy Technology Laboratory. Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies. 12 April 2022. Source

[99] U.S. National Clean Hydrogen Strategy and Roadmap. 2023. Source

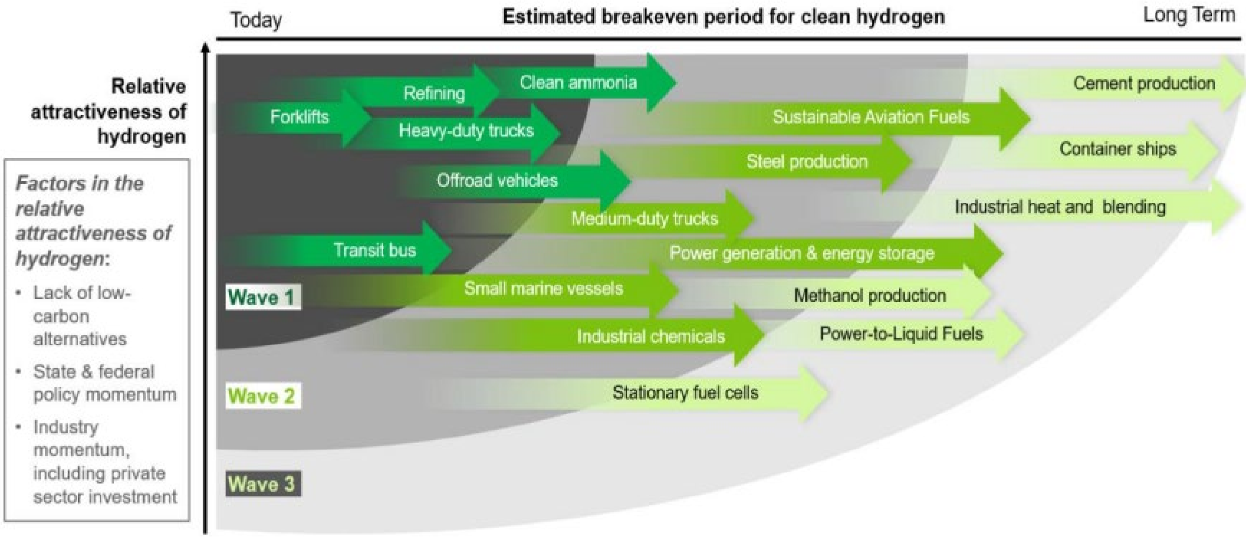


*Figure 22: Anticipated phases for clean hydrogen development (Source: US National Clean Hydrogen Strategy Roadmap)*

With existing gas infrastructure already well-established and spanning vast networks, there is growing interest in utilizing these pipelines for hydrogen transport. One key consideration in transitioning gas infrastructure for hydrogen transport is the compression of hydrogen gas. Hydrogen has a low volumetric energy density compared to natural gas, which means it requires higher pressures to achieve similar energy content, posing a significant need for compression technologies. Also, hydrogen's lower volumetric energy density (approximately one-third of natural gas) necessitates increased flow rates through the existing pipelines to achieve the desired energy delivery. This higher flow rate may lead to increased pressure drops, requiring additional compression along the pipeline to maintain energy transfer efficiency. Integrity management practices must be adapted as well to account for hydrogen's characteristics and ensure the safe operation of the pipeline network. Upcoming pilots and demonstration projects including hydrogen hubs, can provide valuable insights into the practical challenges and opportunities of hydrogen integration with the natural gas infrastructure.

While hydrogen blending is at the forefront of the growing hydrogen markets in the U.S., there has also been interest in pure hydrogen distribution networks. For instance, hydrogen microgrids are being investigated by ATCO and SoCalGas.

**Regulatory Challenges for Alternative Fuel Pipelines**

Of the multiple decarbonization pathways presented in this paper, the case of using alternative fuels in the existing natural gas pipeline network represents the greatest need for additional policy. The transportation of RNG and SNG via pipeline can be regulated much in the same way and by the same federal authorities as conventional natural gas. PHMSA safety regulations and standards apply to RNG and SNG pipelines, and FERC is responsible for reviewing applications for the construction and operation of interstate gas pipelines (Section 7 of NGA).[100] Natural gas pipeline operators must submit an approved tariff and statement of operating conditions to

[100] 18 CFR Part 284. Source.

FERC (under the NGA and NGPA), which describes the operator-developed quality standards for gas being transported by their pipe system. Under this regulatory framework, it is up to each individual operator to revise and include provisions in their tariff that allow for the injection and transportation of RNG and SNG. While this regulatory framework functions and these alternatives are successfully being injected into the natural gas system, establishing federal gas quality standards and requiring operators to consider RNG/SNG concentrations in their tariffs may promote injection and alleviate concerns over the quality of these alternatives.[101]

Unlike RNG or SNG, building out a hydrogen-specific pipeline system or converting natural gas pipes for hydrogen blending poses some unique challenges. The current regulatory framework reflects hydrogen's traditional use as an industrial feedstock and not an energy carrier or fuel-source. For example, FERC has clear jurisdiction over the development of new interstate natural gas infrastructure, but there is currently no dedicated federal authority designated to approve interstate hydrogen pipelines. Developers of hydrogen-specific pipelines must get approval from all the state authorities through which their proposed hydrogen pipe would enter. While this process has been adequate for building the current hydrogen system, it may be prudent to institute federal regulations and standardized processes for interstate hydrogen pipeline siting and permitting as more larger hydrogen systems are developed.

While FERC has authority over the rates of interstate natural gas pipelines and the Surface Transportation Board (STB) regulates hydrogen-specific pipelines as common carriers, there has been some jurisdictional uncertainty over pipelines carrying hydrogen blends. The Natural Gas Act gives FERC jurisdiction over " natural gas unmixed or any mixture of natural and artificial gas," but not over manufactured or "artificial" gas. Whether hydrogen should be classified as a natural or artificial gas is subject to debate, as it is naturally occurring but commonly produced via steam-methane reforming and electrolysis. While FERC has expressly stated its jurisdiction over hydrogen blended pipelines, the appropriate classification of hydrogen remains unclear and leads to some jurisdictional uncertainty for future use-cases. If hydrogen is classified as a natural gas, FERC would maintain jurisdiction over natural gas and hydrogen-specific pipelines in the case of increasing concentrations of hydrogen blending. However, if hydrogen is classified as an artificial gas which FERC does not currently have jurisdiction over, there is an undefined concentration threshold where FERC jurisdiction would hypothetically transition to STB authority in the case of prolonged conversion of natural gas pipelines to hydrogen.[102] Though the blend concentration at which revisions to current laws would be needed has not been examined by FERC, pipeline operators can still choose to carry hydrogen blends by including provisions in their FERC-approved tariffs prescribing the concentration of hydrogen they wish to blend.[103]

Additional clarification on these matters may be needed as the number of hydrogen-specific and hydrogen blended pipelines increases, especially as the federally funded hydrogen hubs begin development. There are also no federal standards for blended gas quality or

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[101] Akin. Renewable Natural Gas: Pipelines, FERC, and Tariffs. Source.
[102] Energy Bar Association. Jurisdiction Over Hydrogen Pipelines and Pathways to an Effective Regulatory Regime. 2022. Source.
[103] Congressional Research Service. Pipeline Transportation of Hydrogen: Regulation, Research, and Policy. March 2021. Source.

interchangeability standards, which are necessary for implementing a successful hydrogen-blending strategy. PHMSA will likely need to develop more hydrogen-related regulations, as there is a significant gap in safety and operational standards for hydrogen blends. As an extremely flammable gas, blended hydrogen introduces new risks for explosion that aren't currently accounted for by PHMSA safety regulations. Because hydrogen has not historically been used as a fuel source, the current laws and regulating authorities may need to be revised or expanded to comprehensively cover alternative fuels before hydrogen and blends can be used safely at scale, especially in the case of long-term transition between gaseous fuels, so that the proper authority can implement the appropriate developmental, operational, and safety standards.[80]

**Estimating Emissions Reductions with Alternative Fuel Pathways**

When evaluating the carbon intensity of a fuel pathway, a comprehensive approach is needed as there is a range of factors within the production, delivery, and end-use process that contribute towards the carbon intensity of a fuel. Factors include feedstock type, feedstock management, electricity source, process emissions, feedstock location and transportation, transportation of fuel to end-use, and forms of end-use. Changes in these factors can significantly affect the carbon intensity of a fuel, and a technology pathway can have a multitude of expected emissions. Therefore, there is a need to conduct holistic regional analyses to determine the best options to decarbonize the gas system given the resources available and demand in an area. The various factors are discussed further below.

- **Feedstock type:** Combining renewable feedstock with traditional emissions-intensive processes (e.g., SMR) can significantly reduce the carbon intensity of a fuel. Given that the carbon content of renewable feedstock varies, the feedstock type utilized will affect the carbon intensity of the fuel produced. As an example, for biomass, it is estimated that using willow wood and switchgrass instead of poplar wood via gasification would result in carbon intensities of 1.00 $CO_2e/kgH_2$ and 1.58 $CO_2e/kgH_2$, respectively, compared to 1.27 $CO_2e/kgH_2$ using poplar wood.[104]
- **Feedstock management:** Where feedstock is derived from and how feedstock is procured and managed play a crucial role in the carbon intensity of a fuel. If feedstocks are derived from unsustainable sources (e.g., deforestation, farming practices involving excessive use of chemicals), the emissions from producing these feedstocks may exceed the savings from using these feedstocks for fuel production. Effective waste management is also key to minimizing methane emissions. One method is to utilize waste-to-energy technologies (e.g., pyrolysis, fluidized bed, rotary kiln, gasification, etc.) to reduce methane that would otherwise be emitted.

[104] GTI Energy. Hydrogen Production Emissions Calculator. The GREET default value for electricity for capture for poplar wood, willow wood, and switchgrass are: 76,802 BTU electricity/MMBTU, 77,241 BTU electricity/MMBTU, and 78,765 BTU electricity/MMBTU, respectively. Additional factors that impact overall carbon intensity include the heating value and carbon content of the feedstock. The heating value and carbon ratio of willow wood, poplar wood, and switchgrass are: 15.396 MMBTU/ton and 48.7%, 15.929 MMBTU/ton and 50.1%, and 14.447 MMBTU/ton and 46.6%, respectively. Source.

- **Electricity source:** If the electricity is generated from only renewable or nuclear sources, there are no associated emissions. However, utilizing only or some carbon-based sources would yield emissions that will increase the carbon intensity of the fuel.
- **Process emissions:** Reducing the energy consumption of feedstock processes would lower the carbon intensity of a fuel. Utilizing more efficient processes and equipment, such as cogeneration and continuous processing, can improve feedstock processing efficiency and yield less emissions.
- **Feedstock location and transportation**: Where the feedstock source is and how the feedstock is transported contribute towards the carbon intensity of a fuel. If the feedstock needs to be transported over long distances from the source to the production site, it would increase the overall carbon intensity. If a region is rich in feedstock, it may be more environmentally favorable to locate a production facility in that area instead of transporting the feedstock. The mode of transportation used is another factor. For example, using heavy-duty diesel trucks to transport feedstock over long distances would contribute more emissions compared to using more energy-efficient vehicles.
- **Fuel-to-end use transportation:** Similarly, how the fuel product is transported would affect the carbon intensity. For example, pipeline transportation generally entails less emissions compared to trucking the fuel.
- **Forms of end-use:** Given that energy efficiency and fuel consumption vary widely across and within end-use sectors[105], estimating emissions reduction of a fuel pathway will need to consider the availability of more efficient technologies and the compatibility of alternative fuels with existing processes. There is also a need to consider the interconnectedness of end-uses, such that reducing the carbon intensity of the electricity that is used by other sectors would lower the carbon intensity of the subsequent end-uses.

## Direct Emissions Management

Direct emissions management plays a critical role in decarbonization efforts as it reduces emissions at the source. Deploying carbon capture, utilization, and storage technologies, improving leak detection, quantification, and measurement capabilities, and replacing aging infrastructure, are several of the most impactful ways to mitigate emissions.

### Carbon Capture, Utilization, and Storage

Carbon Capture, Use, and Storage (CCUS) technology is a set of processes designed to capture $CO_2$ emissions from various sources, utilize the captured $CO_2$ for various purposes, and store it safely to mitigate emissions. CCUS presents an opportunity to provide direct emission reduction at the source, as well as offer infrastructure to recycle emissions for the purpose of fuel production. Several decarbonization pathways have been identified as suitable applications for CCUS to improve overall lifecycle emissions and fuel production yield.

[105] In 2022, the total energy consumed by the transportation sector, industrial sector, and power generation sector, was 27,538.703 trillion Btu, 32,912.459 trillion Btu, and 37,751.371 trillion Btu, respectively. Source

**Technology Landscape**

The CCUS technology landscape and analysis encompass the different approaches, challenges, and potential benefits associated with implementing CCUS on a national to global scale. Developing the necessary infrastructure for large-scale CCUS deployment, including pipelines and storage sites, can be complex and expensive, requiring significant upfront investments. Nevertheless, by harnessing the potential of CCUS, operators can take significant steps toward decarbonization and building a sustainable energy future. Collaboration, supportive policies, and public acceptance will be key drivers for widespread adoption. There are three main sections to the CCUS value chain:

1- **Carbon Capture Technologies**
   - Post-combustion capture: This technology captures $CO_2$ from flue gases after fossil fuels are burned in power plants or industrial facilities.
   - Pre-combustion capture: It captures $CO_2$ before fuel combustion by converting fossil fuels into syngas, which is then further processed to remove $CO_2$.
   - Oxy-fuel combustion: This approach burns fuels in oxygen instead of air, resulting in a flue gas primarily composed of $CO_2$, which can be captured more easily.
   - Carbon Dioxide Removal (CDR): It encompasses various activities that remove $CO_2$ from the atmosphere, ranging from tree planting to direct air capture (DAC) facilities. DAC involves extracting $CO_2$ directly from ambient air using various chemical processes.

2- **Carbon Utilization Technologies**
   - Enhanced oil recovery (EOR): Captured $CO_2$ is injected into depleted oil fields, enhancing oil recovery while simultaneously storing the $CO_2$ underground.
   - Carbonation: $CO_2$ is reacted with minerals to form stable carbonates, which can be used in construction materials or stored underground.
   - Synthetic fuels and chemicals: $CO_2$ can be converted into fuels or chemicals through processes like electrolysis or chemical reactions.
   - Algae cultivation: $CO_2$ is used as a feedstock for cultivating algae, which can be used for biofuel production or as a food source.

3- **Carbon Storage Technologies**
   - Geological storage: $CO_2$ is injected deep underground into geological formations, such as depleted oil and gas reservoirs or saline aquifers ().
   - Ocean storage: $CO_2$ is injected into the deep ocean, where it can dissolve or form mineral carbonates.
   - Mineralization: $CO_2$ reacts with certain minerals to form stable carbonates, which can be stored underground.

In most CCUS projects, the primary expense is associated with the capture phase, while the viability of these projects relies heavily on the presence of reliable transportation, storage, or utilization networks. CCUS can play a vital role in reducing GHG emissions, especially from hard-to-abate sectors like heavy industry. While continued innovation and research efforts are necessary to drive down the costs associated with CCUS technologies and make them economically viable at a larger scale, adequate financial support and investment are crucial for the widespread deployment of CCUS technologies. Governments, private sector entities, and international funding mechanisms should continue to allocate resources to support research, development, and implementation. Governments and private sector entities can establish incentives and reward mechanisms for carbon removal technologies, encouraging innovation and investment in these approaches. These actions can facilitate the transition from fossil fuels to a net-zero emissions economy by providing bridge technologies.

**Current Deployment and Initiatives**

As Figure 23 below displays, the US has significant potential for underground storage of CO2 with abundant depleted oil and gas sites spread across the country. Several large-scale CCUS projects are in operation or under development worldwide, showcasing the feasibility and effectiveness of these technologies. These projects serve as important demonstrations of the potential of CCUS to accelerate decarbonization. One notable example is the Petra Nova project in Texas.[106] The project captures post-combustion $CO_2$ from a coal-fired power plant and transports it via pipeline to the West Ranch oilfield for storage for utilization in EOR. The Plant Barry Carbon Dioxide Capture and Storage Project[107], led by Alabama Power Company, Southern Company, and Mitsubishi Power Americas, focuses on capturing $CO_2$ emissions from the flue gas of the Plant Barry coal-fired power plant. The captured $CO_2$ is then transported via pipeline and injected into a deep saline aquifer located approximately 10,000 feet below the surface.

NET Power[108] is a company in Texas that has developed an innovative natural gas power plant with zero emissions. The plant uses the Allam Cycle, a novel combustion technology that combines oxy-fuel combustion with a supercritical $CO_2$ turbine for power generation. NET Power highlights the ongoing efforts in the US to explore and implement innovative solutions for capturing and storing $CO_2$ emissions.

Moreover, there are over a hundred projects in various stages of development, indicating the growing momentum and interest in this field. The ADM Carbon Capture Project, located in Decatur, Illinois, is a collaborative effort between Archer Daniels Midland Company and the Illinois Industrial Carbon Capture and Storage (ICCS) project. The project captures $CO_2$ from an ethanol production plant and transports it via pipeline for storage in the Mount Simon Sandstone, a deep saline aquifer[109]. The National Carbon Capture Center[110], located in Wilsonville, Alabama, is a research facility dedicated to advancing carbon capture technologies. It serves as a testing ground for various carbon capture technologies and collaborates with industry, government agencies, and research institutions to accelerate the deployment of CCUS

[106] DOE. Secretary Perry Celebrates Successful Completion of Petra Nova Carbon Capture Project. 13 April 2017. Source
[107] Mitsubishi Heavy Industries. MHI Carbon Capture Technology to be Demonstrated in United States on Southern Company Coal-Fired Power Plant. 22 May 2009. Source
[108] NET Power. Technology. 11 July 2023. Source
[109] ADM. ADM and Carbon Capture and Storage. 11 July 2023. Source
[110] National Carbon Capture Center. 11 July 2023. Source

technologies.

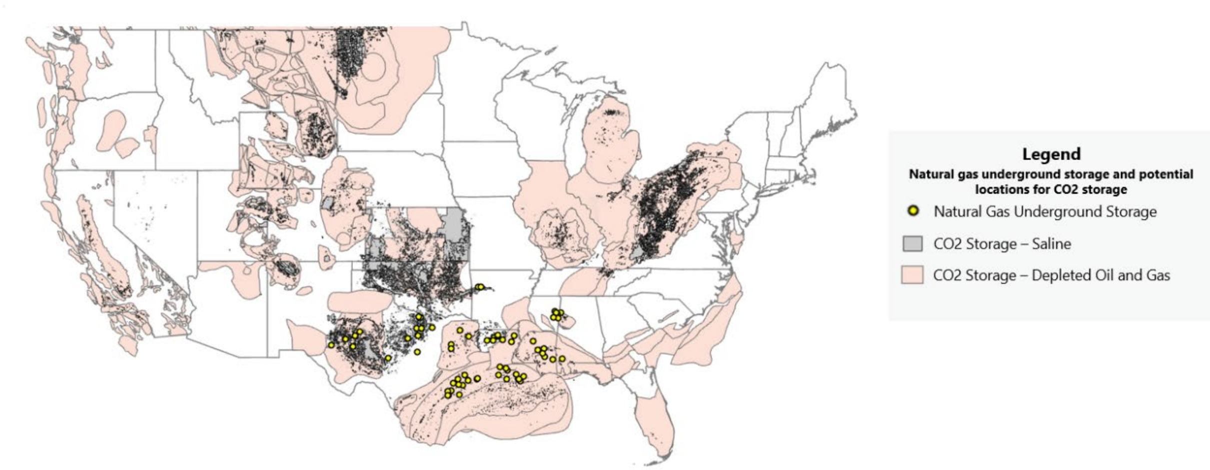


*Figure 23: Natural gas underground storage and potential locations for $CO_2$ storage (Source: EIA[111]; NATCARB[112])*

In addition to carbon capture and storage, there are initiatives exploring carbon capture and utilization, which involves capturing $CO_2$ emissions and converting them into valuable products. For instance, Carbon Clean Solutions, in collaboration with Tuticorin Alkali Chemicals and Fertilizers, has implemented a project in India that captures $CO_2$ emissions from a coal-fired power plant and converts it into soda ash, a widely used chemical in various industries[113]. Carbon Engineering, a Canadian company, has implemented a DAC facility in Squamish, British Columbia[114]. The facility captures $CO_2$ from the air using large-scale mechanical systems and converts it into a purified form suitable for storage or utilization.

These examples highlight the ongoing efforts and initiatives to deploy and advance carbon capture and storage technologies. They demonstrate the growing interest and commitment to leveraging CCUS technologies as essential tools for achieving emissions reduction goals.

**Future Outlook**

To effectively meet the 2050 net-zero emission goals, CCUS deployment needs to be significantly scaled up. Scaling up the demonstration of CCUS projects is crucial to prove the viability, scalability, and effectiveness of the technologies in real-world applications. Governments and industry stakeholders should support the deployment of large-scale

[111] US Energy Information Administration, "Natural Gas Underground Storage," Source
[112] The National Carbon Sequestration Database and Geographic Information System (NATCARB), "NATCARB_OilGas_v1502," Source
[113] Carbon Clean. New project will see more than 60,000 tonnes of CO2 captured. 13 October 2016. Source
[114] Carbon Engineering. Engineering begins on large-scale commercial facility in Canada to produce fuel from air. 14 October 2021. Source

demonstration projects to gather valuable data and build confidence in CCUS. This requires sustained investments, policy support, and collaboration among governments, industries, and research institutions.

Governments and international organizations have recognized the importance of CCUS and are implementing policies and incentives to support its deployment, which includes funding research and development, providing grants and subsidies, and establishing regulatory frameworks. The US and Canada have been at the forefront of CCUS deployment, with several projects in operation. The 45Q tax credit in the US provides financial incentives for carbon capture and storage projects, which can help offset the high upfront costs and promote private sector investments. Long-term financing mechanisms, such as carbon contracts for difference (CCfDs)[115] can provide stable revenue streams and reduce investment risks for CCUS projects, encouraging private sector participation. Clear, stable, and long-term policies that incentivize the deployment of CCUS technologies can provide regulatory certainty, streamline permitting processes, and address potential liabilities associated with carbon storage.

To help harmonize standards and create a supportive landscape for CCUS deployment, governments and policymakers should foster a learning environment where policies and regulations can be adapted based on the evolving understanding of CCUS technologies and their potential impact. Flexibility and adaptive governance can facilitate effective implementation. For example, implementing standardized carbon accounting and reporting systems is crucial for tracking and verifying the $CO_2$ emissions captured, stored, or utilized by CCUS projects to establish transparency, comparability, and accountability across different projects and industries.

Since the CCUS technology landscape is diverse and evolving, with ongoing efforts to improve capture, utilization, and storage processes, encouraging the exchange of research findings, data, and best practices among academia, industry, and governments can accelerate the development and deployment of CCUS technologies. Collaborative initiatives such as the Global CCS Institute, the Carbon Capture, Utilization, and Storage Initiative (CCUS Initiative), and the Clean Energy Minsterial's CCUS Action Group aim to share knowledge, promote technology development, and facilitate information exchange among stakeholders.

Furthermore, it is important to note that public perception plays a significant role in the acceptance and adoption of CCUS technologies. Efforts should be made to raise awareness, educate the public, and address any misconceptions or concerns related to CCUS, emphasizing its potential benefits in reducing emissions and mitigating climate change. Communicating the importance of CCUS in achieving net-zero emission goals and addressing concerns regarding safety and environmental impacts is essential. Engaging with local communities, industry

[115] Carbon contracts for difference (CCfDs): involves national governments providing extended contracts to cover the gap between the existing carbon price and the real cost of reducing CO2 emissions.

representatives, and environmental organizations in the planning and decision-making processes can help address concerns, ensure transparency, and build trust. Exploring decentralized and community-based CCUS solutions can empower local communities and promote their active participation. This approach can foster a sense of ownership, generate economic opportunities, and address regional-specific challenges.

Finally, scaling up CCUS deployment requires the development of a robust infrastructure, including $CO_2$ transport and storage networks, to enable the efficient and cost-effective implementation of CCUS projects. The US currently has over 80% of the global $CO_2$ pipeline infrastructure, boasting an extensive network that spans approximately 5,000 miles[116]. The development of expanded $CO_2$ transport networks is crucial to connect $CO_2$ capture sources with suitable storage sites.

Repurposing natural gas pipelines for $CO_2$ transport and leveraging the right of ways is an emerging approach that can contribute to the development of $CO_2$ transport infrastructure for carbon capture and storage (CCS) projects. Natural gas pipelines have existing networks and infrastructure that can be utilized to transport $CO_2$ from capture sites to storage or utilization sites. Repurposing pipelines offers several advantages, including cost savings, reduced environmental impact, and accelerated deployment. Repurposing natural gas pipelines requires retrofitting and modifications to ensure compatibility with $CO_2$ transport. $CO_2$ has different characteristics than natural gas, and the pipeline system must be adapted to accommodate the unique properties of $CO_2$. This may involve changes in pipeline materials, corrosion prevention measures, and modifications to compression and pumping systems. Proper engineering design and adherence to safety standards are essential to ensure the safe and efficient transport of $CO_2$ through repurposed pipelines.

**Regulatory Challenges for $CO_2$ Pipelines**

The regulation of CO2 pipelines is currently a topic of great jurisdictional confusion, similar to that of hydrogen and hydrogen-blended natural gas pipelines. Because FERC and the STB have both declined to hold jurisdiction over CO2 pipelines, the regulation of pipeline siting primarily falls under the jurisdiction of individual states. With no federal authority to oversee development, state authorities are often responsible for granting permits and determining the use of eminent domain, which allows the acquisition of necessary rights of way for pipeline development. As a result, pipeline developers must seek the approval of each individual state authority through which their proposed pipeline would enter. States are also responsible for setting their own guidelines for CO2 pipeline interconnection, resulting in inconsistent or nonexistent standards between states that pipeline operators must reconcile.[117]

While PHMSA is responsible for implementing safety regulations for interstate and some intrastate CO2 pipelines, an issue of legislative definition has led some to question this authority. The Pipeline Safety Reauthorization Act of 1998 defined CO2 as “a fluid consisting of more than 90% CO2 molecules compressed to a supercritical state.” The issue is that when CO2 is transported via pipeline it typically switches between supercritical and liquid or gas phases due

116 Institute for Energy Research, 2023. Source

117 NARUC. Onshore U.S. Carbon Pipeline Deployment: Sitting, Safety, and Regulation. June 2023. Source.

to changes in temperature alone the pipeline, resulting in uncertainty over which authority, of any, is responsible for overseeing them. PHMSA is currently in the process of updating its regulations to enhance safety measures after a CO2 pipeline ruptured in 2020, and will hopefully provide clarification on this matter. The first draft of these revisions is not expected to be completed till October of 2024, and with federal funding spurring the development of more CCUS projects and CO2 pipelines, some operators have called for a moratorium on construction until additional CO2-specific regulations and standards are developed.[118]

Carbon sequestration is an important aspect of enabling flexible utilization of $CO_2$ pipeline networks. Long-term geological sequestration of carbon dioxide is regulated by the EPA in the form of Class VI permits, first introduced in 2010 with the United States Environmental Protection Agency's (EPA's) Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells (75 FR 77230, December 10, 2010). EPA is currently processing numerous Class VI permits, most of which pertain to projects located in Region 6 (Arkansas, Louisiana, New Mexico, Oklahoma, Texas and 66 Tribal Nations) in October 2023[119]. There are a significant number of states that require EPA regulatory approval for Class VI permit issuance. As of 2023, there are only two states that have primacy for Class VI wells, being North Dakota and Virginia[120]. Only six states have passed state-level legislation addressing the long-term liability and transfer of storage site ownership from operator to state once injection is complete. The timeframe for liability transfer ranges from immediate to 30 years after well closure, with one state declaring it would never be liable for any CO2 injection wells.[121]

**Advancing Energy System Integration - Fostering Synergy and Resilience**

Collaboration among different sectors, including energy, transportation, industry, and agriculture, is crucial for the economical deployment of CCUS technologies. Integrated approaches that address emissions from multiple sectors can lead to more comprehensive and cost-effective solutions. For example, retrofitting existing industrial facilities with carbon capture technologies can significantly reduce their emissions and extend their operational lifespan. Supporting retrofit programs and providing financial incentives can encourage industries to invest in CCUS and decarbonize their operations. Integration of carbon capture technologies with industrial clusters, where multiple industrial facilities are located in close proximity, can optimize the capture and utilization of $CO_2$ emissions. This integration enables shared infrastructure and cost efficiencies, enhancing the overall viability of CCUS.

CCUS provides a viable option for decarbonizing heavy industries like cement, steel, and chemicals. Additionally, the utilization of captured $CO_2$ can create new opportunities for value-added products and circular economy approaches. Adopting a circular economy approach can enhance the effectiveness of CCUS technologies. By integrating carbon capture and utilization processes with industries that require $CO_2$ as a feedstock, such as the production of fuels or

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[118] IER. 2023. Are CO2 Pipelines Regulated? By Whom? Source.
[119] U.S. EPA, 2023. Current Class VI Projects under Review at EPA. Source
[120] U.S. EPA, 2023. Primary Enforcement Authority for the Underground Injection Control Program. Source
[121] Massachusetts Institute of Technology, 2020. Regulation for Undergrounf Storage of CO2 Passed by U.S. States. Source.

building materials, the overall emission reduction benefits can be maximized. Integration of CCUS with renewable energy sources, such as solar and wind, can create synergies by utilizing excess renewable energy to power carbon capture processes or utilizing $CO_2$ emissions for renewable fuel production. CCUS can also play a significant role in the production of low-carbon hydrogen, by capturing and storing $CO_2$ emissions generated during hydrogen production from fossil fuels. Governments and regulatory bodies play a crucial role in promoting the integration of CCUS with renewable energy systems. By implementing supportive policies, such as feed-in tariffs, renewable energy mandates, and incentives for CCUS deployment, they encourage the adoption of these combined technologies. Policy frameworks that incentivize the use of renewable energy in CCUS processes can drive investment, research, and development in this field.

Currently, the expansion of CCUS is predominantly focused on industries that have relatively low costs associated with capturing $CO_2$ enabled by high-purity $CO_2$ streams such as those found in ethanol production and natural gas processing. Business case analysis indicates that these CCUS projects when coupled with the improved 45Q tax credit provided by the Internal Revenue Service (IRS), could potentially achieve internal rates of return (IRRs) of 10-15% or even higher without taking into account any financial leverage. Notably, capturing CO2 from ethanol fermentation processes costs less than $30 per ton, while the 45Q CCS subsidy amounts to $85 per ton. This cost-efficient synergy underscores the economic viability of these projects and the potential for an additional revenue stream, reinforcing their value in emissions reduction endeavors.

While the 45Q tax credit currently serves as the primary incentive for carbon management in the US, its expiration for new projects beginning construction after 2032 is expected. Industry players across CCUS believe that future growth in carbon management must be driven by a combination of regulations and private sector actions such as extending the 45Q tax credit, regulating emissions standards, cap and trade programs or carbon taxes, as well as supporting alternative revenue streams like voluntary carbon markets, technology premiums, premium Power Purchase Agreements (PPAs), and revenues from other products. These measures aim to incentivize and sustain the progress of carbon management, ensuring continued efforts to address carbon emissions and promote sustainable practices.[122]

### Improving Methane Emissions Detection, Quantification, and Measurement

The are two types of methane emissions estimation methodologies commonly used in the natural gas industry today. The bottom-up or conventional inventory-based methodology uses standardized, averaged asset emission factors and asset inventories to estimate emissions from across the natural gas supply chain without having to make extensive and expensive direct measurements. Top-down approaches use direct, short, or long-term emissions measurement data to estimate the frequency and duration of leaks, which is then extrapolated to account for all assets.

[122] DOE. DOE Releases Fourth Pathways to Commercial Liftoff Report in Carbon Management. 24 April 2023. Source

While bottom-up estimations are often mandated by regulatory agencies for use in emissions reporting, several studies have found this methodology to inaccurately estimate actual emissions and highlight significant differences between calculated methane emissions and measured emissions. This is in part due to the fact that federally approved emission factors are typically based on past scientific studies, which can be outdated or limited in the number of measurements used to develop them. Thus, emissions estimates calculated using the bottom-up methodology do not rely on the current operational state of natural gas systems and therefore make company performance comparisons unreliable. Because bottom-up estimates are based on emission factors and asset inventories, they fail to account for large, sporadic releases of methane.  These events, called super emitting events, can account for up to 12% of the total methane emissions from oil and gas production and transmission, meaning bottom-up estimations often underestimate actual emissions.[123]

The quantity of direct measurements required in top-down methodologies to produce regularly updated and localized emissions estimates has not historically been possible but has become more attainable with recent advancements and increased availability of methane detection and quantification technologies. These new technologies can provide measurements at varying spatial and temporal scales and frequently provide top-down or whole-site emission measurements, leading to rapid improvements in the accuracy of emissions detection, quantification, and measurements.

**Implementing Advanced Measurement Technology**

Emissions detection technology has progressed immensely in the last few decades and consistent adoption is a key driver in fugitive emissions reductions. When detection technologies are utilized in tandem with long-term leak detection and repair programs, total emissions can be reduced by over 40% after appropriate repairs are made following the initial leak survey.[124] Many of the technologies and measures that are used to prevent methane emissions are well-known and have already been deployed in various locations around the world. In fact, in the latest IEA report on net zero transitions, they expect oil and gas producers in 2030 to have an emissions intensity similar to the world’s best operators today. All of that means that no grand leaps in technology or knowledge are needed to attain these emission reductions. That same IEA report lists multiple examples of methods to curb emissions including leak detection and repair campaigns, installing emissions control devices, and replacing components that emit methane by design.[125]  Figure 24 below summarizes some of the available advanced technologies by their detectable emission rate, standard frequency of deployment, and the level at which you would expect them to be deployed. Advanced technologies like satellite or aerial IR optical imaging, unmanned aerial vehicles (UAVs), mobile vehicle path methods, and Optical Gas Imagers (OGIs).

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[123] Lauvaux, *et al.*, 2022. Global assessment of oil and gas methane ultra-emitters. Source.

[124] Arvind P Ravikumar *et al* 2020 *Environ. Res. Lett.* **15** 034029. Source

[125] International Energy Agency (2023), Emissions from Oil and Gas Operations in Net Zero Transitions 2023, IEA, Paris. Source

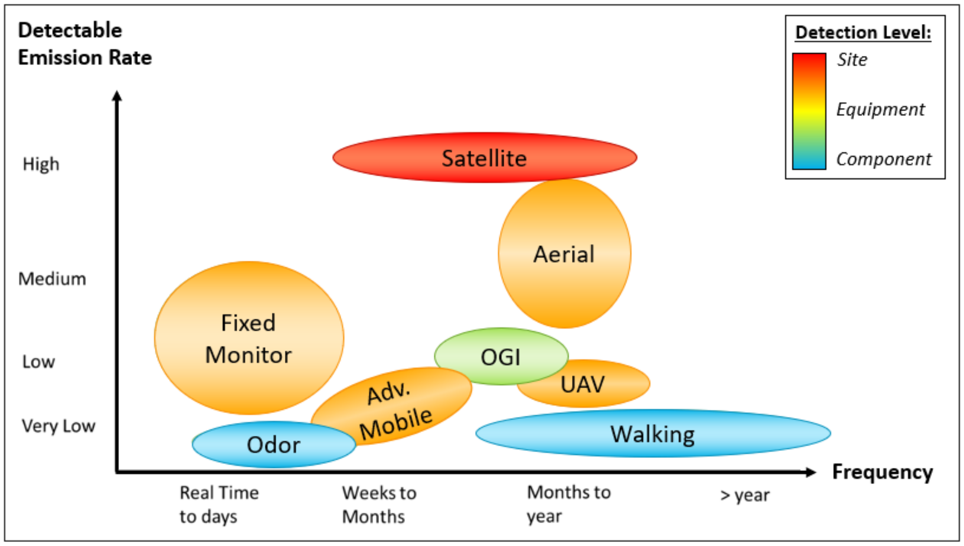


*Figure 24: Summary of available leak detection and quantification platforms*

**The Value of Avoided Emissions**

While investing in emissions detection and measurement technology can have a large up-front cost, it also represents a notable value from both the sale of gas that would otherwise be lost through leaks and from avoided health and climate impacts related to methane emissions. By deploying advanced leak detection technology, operators can address leaks quickly and avoid losses in revenue from products being lost to the atmosphere. Regulatory impact analyses of policy supporting improved leak detection have attempted to estimate the value of these avoided losses. For instance, the EPA estimates that adopting one such policy, The Supplemental Proposal to Reduce Methane and Other Harmful Pollution from Oil and Gas Operations,[126] would reduce methane emissions from source categories by 87% in 2030 from 2005 levels and avoid an estimated 36 million tons of methane from now to 2035. The leak detection and measurement requirements in this policy would prevent $3.3 to $4.6 billion in natural gas from being lost through leaks from 2023 to 2035 based on forecasted prices. This EPA analysis also examined the value of avoided climate-related impacts resulting from decreased methane emissions from now to 2035 and valued it at $34 to $35 billion; representing $3.1 to $3.2 billion gain per year through climate benefits. For operators, this means that many measures are cost-saving on their own. Oftentimes, the cost of deploying an emission-reducing technology is less than the market value of the methane that is captured and can subsequently be sold resulting in a negative cost per ton of CO2 equivalent avoided. Figure 25 estimates the costs associated with various methane emission reduction methods and many forms of upstream LDAR, for example, have a net negative cost when accounting for methane saved and sold. If implemented well, a 75% reduction in emissions by 2030 would on average add just USD 0.05/boe to the cost of producing oil and gas in the net-zero emissions scenario.

[126] EPA's Supplemental Proposal to Reduce Pollution from the Oil and Natural Gas Industry to Fight the Climate Crisis and Protect Public Health: Overview. Source

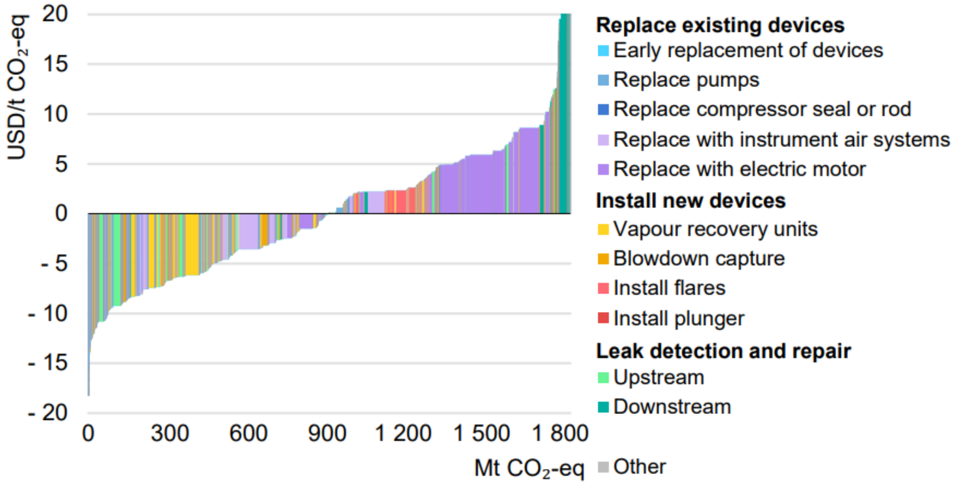


*Figure 25. Costs of avoiding methane emissions in O&G operations (Source: International Energy Agency (2023), Emissions from Oil and Gas Operations in Net Zero Transitions 2023, IEA, Paris)*

The value of emissions-related health impacts has become a point of interest over recent years, especially in relation to the growing concern over environmental injustices from the oil and gas industry. In this context, environmental injustice refers to the unfair burden and negative impacts that disadvantaged communities have historically been exposed to by the industry[127]. One of these burdens is increased exposure to air pollutants like methane, ozone, particulate matter, and nitrous oxide due to the higher concentration of natural gas infrastructure often found within and around disadvantaged communities. Exposure to these air pollutants is linked to increases in respiratory and cardiovascular health complications, including heart attack and asthma. One recent study from the Boston University School of Public Health[128] estimated that exposure to these air pollutants from U.S. natural gas production in 2016 resulted in 2,200 new cases of childhood asthma, 410,000 cases of asthma exacerbation, and 7,500 excess deaths; the total value of which was estimated to be $77 billion. Based on analyses like the ones above, advanced leak detection and measurement technologies are an economically efficient investment that provides value to not only operators within the oil and gas industry but to society as a whole.

**Voluntary Methane Emissions Reduction Initiatives**

There is a rapidly growing number of country-based and global methane emission reduction initiatives that companies can align with voluntarily as the demand for methane emissions management grows to encompass the entire oil and gas supply chain. In a constantly changing emissions management landscape, companies and customers alike are seeking comprehensive guidance for particular industries, segments, or specific elements of their respective emissions management strategies.

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[127] EPA's Proposal to Reduce Climate- and Health-Harming Pollution from the Oil and Natural Gas Industry: Addressing Environmental Justice Concerns Source

[128] Buonocore, J. J., et al. 2023. Air pollution and health impacts of oil & gas production in the United States. Source

Some voluntary initiatives provide guidelines to help entities meet their specific methane emissions reduction targets (Table 2), like Veritas, GTI Energy's methane emissions measurement and verification protocols.[129] These protocols outline a standardized, science-based, technology-neutral, measurement-informed approach to calculating and reporting methane emissions. Veritas provides different protocols for each segment of the natural gas industry, which outline a methodology for how to measure methane emission and how to reconcile bottom-up emission-factor inventories with measurements. The overall objective for companies implementing the Veritas protocols is to produce a measurement-informed methane emissions inventory for their respective natural gas assets. The protocols were publicly released in February 2023.

*Table 2: Methane Emission Reduction Guidelines for the Natural Gas Industry (as of 2022)*

| Initiative | Segment | Organization | Level of Engagement | Coverage |
|---|---|---|---|---|
| **Veritas Protocols** | Production, gathering & boosting, processing, transmission, distribution, LNG | GTI Energy | 35+ companies | Global |
| Veritas Protocols provide industry with guidelines on using site-level rate measurements and reconciliation. The protocols provide guidance on a science-based, broadly comparable set of steps required to create a measurement-informed methane emission inventory specific to a company. | | | | |
| **The Methane Challenge Program** | Production, gathering & boosting, transmission and storage, distribution | US EPA | 60 companies | USA |
| The Methane Challenge Program publicly recognizes U.S. companies in the oil and gas sector that commit to reduce methane emissions by either implementing emissions-reducing technologies and best management practices or by showing progress according to ONE Future Emissions Intensity reporting protocols. | | | | |
| **NGSI Methane Emissions Intensity Protocol** | Production, gathering & boosting, processing, transmission, distribution | AGA and EEI | American Gas Association (AGA) and Edison Electric Institute (EEI) members | USA- onshore |
| The Methane Emissions Intensity Protocol provides source-specific quantification methods and emission factors. | | | | |
| **CDP Scores** | Production, gathering & boosting, processing, transmission, distribution, LNG | CDP | 249 companies | Global |

[129] GTI Energy's Methane Emissions Measurement and Verification Initiative. Source

| | | | | |
|---|---|---|---|---|
| CDP Scores rate participants based on their responses to detailed questionnaires focused on climate change, water security, and forest sustainability. Participants can choose to take part in any or all of the three focus areas. | | | | |
| **Global Reporting Initiative 11: Sector Standards for Oil and Gas** | Production, gathering & boosting, processing, transmission, distribution, LNG | Global Reporting Initiative (GRI) | Unknown | Global |
| GRI Standards are full ESG guidelines that focus on the disclosure of outward impacts of the company's activities. Engagement in this initiative allows companies to communicate to stakeholders the actions they are taking to address and mitigate external impacts on the environment and the community. | | | | |
| **Task Force for Climate-related Financial Disclosures (TCFD) Framework** | Production, gathering & boosting, processing, transmission, distribution, LNG | Financial Stability Board | Unknown | Global |
| Engagement in the TCFD Framework allows companies to communicate their activities that address identified material risk due to climate change to the company's sustainability. As a complete ESG framework, the focus is given to the inward impacts of climate change on the company's sustainability. | | | | |

**Modified from Highwood Emission's Voluntary Emissions Reduction Initiatives Report[130]*

Another type of voluntary initiative is emissions reduction commitment in which entities make a pledge to meet specified methane emissions reduction targets, with regular and transparent progress checks and reports (Table 3). One such commitment program is the Climate and Clean Air Coalition's Oil and Gas Methane Partnership (OGMP) 2.0,[131] a global initiative developed in 2014 with the United Nations Environmental Program (UNEP) as part of the Mineral Methane Initiative. Members must pledge their commitment by signing a Memorandum of Understanding and setting their own company-specific methane emissions reduction goals. OGMP 2.0 also outlines a measurement framework designed to help entities in the oil and natural gas industry track and reduce their methane emissions with improved reporting accuracy and transparency at its core. Participants are required to progress towards the framework's gold standard of reporting within an established timeframe and must continue efforts to improve reporting at the risk of losing this status. The data reported through OGMP 2.0 works in tandem with the International Methane Emissions Observatory to track global progress towards meeting emissions reductions set forth in the Global Methane Pledge and Paris Agreement. The ultimate goal of this initiative is to reduce global industry methane emissions by 60 to 75% by 2030.[132]

[130] HighWood Emissions Management Voluntary Emissions Reduction Initiatives in 2022. Source
[131] OGMP 2.0. Source
[132] Oil and Gas Industry commits to new framework to monitor, report and reduce methane emissions. Source

*Table 3: Methane Emission Reduction Commitments for the Natural Gas Industry (as of 2022)*

| Initiative | Segment | Organization | Level of Engagement | Coverage |
|---|---|---|---|---|
| **Oil and Gas Methane Partnership (OGMP) 2.0** | Production, gathering & boosting, processing, transmission, distribution, LNG | UNEP, CCAC, European Commission, EDF | 79 organizations | Global |
| OGMP provides a framework for producers who are considering source-level measurement for all sources. Achieving the Gold Standard allows producers to credibly report on methane emissions performance to stakeholders. | | | | |
| **ONE Future Methane Intensity Protocol** | Production, gathering & boosting, processing, transmission, distribution | ONE Future Coalition | More than 50 member companies | USA |
| US companies engaged with the ONE Future Coalition are up to speed with the latest developments regarding methane emissions management to achieve the one percent or less methane intensity goal. ONE Future provides guidance and a consistent framework to assist its members in achieving other third-party certifications. | | | | |
| **Oil and Gas Climate Initiative** | Production, gathering & boosting | Oil and Gas Climate Initiative (OGCI) | 12 member companies, over 100 external organizations | Global |
| OGCI develops best practices, shares knowledge, invests, and supports the deployment of low-carbon technologies in OGCI / non-OGCI member companies' assets. | | | | |
| **EPA Methane Challenge Program** | Production, gathering & boosting, processing, transmission, distribution | US EPA | 70 companies | USA |
| Participants commit to short-term methane mitigation activities, wherein they may focus their emissions reductions from one or more sources, implement activities from a list of best management practices, or set a company-wide timeframe for implementation of best practices within five years of the start date. | | | | |

*Modified from Highwood Emission's Voluntary Emissions Reduction Initiatives Report*[115]

Additional initiatives are available, like TrustWell Responsible Gas, that provide operators with a certification for meeting certain environmental, social, and governance (ESG) requirements in their operations and procedures (Table 4). TrustWell provides verification on specific performance metrics for individual operators, like methane intensity and methane reduction factors, and is given a responsibility score.[133] Scores fall within 3 levels representing an operator's overall ESG responsibility- Silver-certified operators are verified as more responsible than 50% of other operators, Gold is verified as 75% more responsible, and Platinum is verified as 90% more responsible.[134]

[133] TrustWell Standard Definitional Document. Source
[134] Project Canary TrustWell. Source

Regardless of the type, voluntary programs like these are opportunities for natural gas entities to demonstrate their commitment to achieving ambitious emissions reductions and meet consumer demand for low-emission energy.

*Table 4: Methane Emission Reduction Certifications for the Natural Gas Industry (as of 2022)*

| Initiative | Segment | Organization | Level of Engagement | Coverage |
|---|---|---|---|---|
| **EO100™ Standard for Responsible Energy Development** | Production, gathering & boosting, processing | Equitable Origin | 24 companies with certification or undergoing certification (10 certified sites with 11 bcf/day certified) | Global |
| The EO100™ Standard provides an independently-audited full ESG reporting suite that considers impacts to all areas of environment, social, and governance including a focus on Indigenous Peoples' rights. | | | | |
| **The MiQ Standard** | Production, processing† | The MiQ Foundation | 14 facilities (total of 600 bcf certified) | USA |
| The MiQ Certification process evaluates the deployment of methane monitoring technology and alignment of company policies to methane management. Certificates are issued, transferred, tracked, and retired through the MiQ Registry. The certificates provide buyers with an audited assurance of differentiated gas production. | | | | |
| **TrustWell™ Responsible Gas** | Production, gathering & boosting, transmission, storage | Project Canary | 33 TrustWell, 58 total customers (more than 4,000 active certificates, cumulative volume of 2,538 bcfe/year) | North America, UK, Asia Pacific |
| TrustWell Responsible Gas focuses on critical elements in well operations. This initiative evaluates well-level environmental performance, including methane emissions, and rates participants as Silver, Gold, and Platinum. | | | | |

**Modified from Highwood Emission's Voluntary Emissions Reduction Initiatives Report*[115]
*†Additional segments being piloted.*

## Replacing Aging Infrastructure

As discussed in previous sections, the US pipeline infrastructure is an extensive network that dates back to the early 1900s. Replacing aging infrastructure serves several purposes: ensuring the safety of people and property by replacing pipelines that are past their material integrity lifetimes and/or highest-risk (e.g., cast and wrought iron, bare steel), enabling the continued use of other parts of existing infrastructure that are still fit for service, and reducing emissions from pipeline materials that are more susceptible to leakage or failure. Because pipeline material, age, and the interaction of the two positively affect the rate of pipeline leakage, replacing aging pipeline infrastructure with modern materials can significantly reduce leakage and fugitive emissions (Figure 26).[135] Modern pipelines are of higher quality and are less prone to

135 Weller, *et al.*, 2020. A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems. Source.

manufacturing and construction defects[136], thereby minimizing the risk of degradation and failure. For example, the replacement of cast iron and bare steel pipelines has reduced reported fugitive emissions in the natural gas distribution systems between 1990 and 2022.[137]

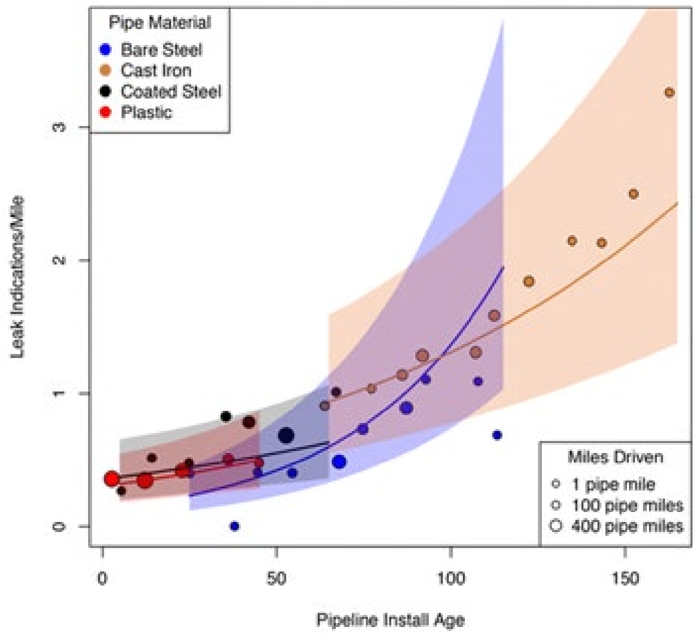


*Figure 26. Estimated activity factors as a function of pipe installation age and material (Source: Weller, et al. (2020))*

Pipeline replacement programs also support the transition to low-carbon alternative fuels such as hydrogen and biogas. Depending on operating conditions, modern pipelines may be more suitable for transporting these fuels with greater material integrity. Pipelines enable more energy-efficient and lower-cost delivery of these fuels over long distances. Leveraging the pipeline system would facilitate scale-up of these fuels by reducing costs and providing greater access. As previously noted, the replacement of aging service lines, distribution, and transmission main pipelines is estimated to take over 100 years based on current replacement rates. Therefore, there is a need to further invest in replacement programs to accelerate emissions reduction and support continued pipeline safety.

**Regulation of Aging Infrastructure Replacement**

Natural gas infrastructure regulation has evolved over the years as a partnership between state and federal authorities and a balance between requirements and incentives. For example, FERC primarily oversees the planning, permitting, and licensing of interstate pipeline infrastructure (Natural Gas Act, Natural Gas Policy Act Sec. 284.11) while intrastate development is left to individual state jurisdiction. In a similar fashion, PHMSA sets the minimum federal safety standards for the transportation of flammable gases like natural gas via pipeline (49 C.F.R. Part

[136] Battelle Memorial Institute. Integrity Characteristics of Vintage Pipelines. October 2004. Source
[137] U.S. EPA. EPA Greenhouse Gas Emissions Inventory. 2022. Source

192) which individual states can comply with or improve upon in their own pipeline safety requirements. Because these federal agencies set the minimum standards for the country, it is crucial they steadily increase pressure to decrease emissions from natural gas infrastructure while providing support to operators who may be unable to bear the financial burden of system modernization.

Current PHMSA regulations related to the replacement of high-emitting pipelines center around safety, as materials like cast iron have a higher rate of corrosion and graphitization compared to low-emitting materials like plastic.[138] Policies such as the PIPES Act of 2020 and 49 CRF 192.613 push for the replacement of pipes known to leak as precautions against pipeline failure, but do not set a timeline for when high-emitting pipes must be removed. In lieu of a requirement such as this, several notices and bulletins have been published by PHMSA[139] urging state authorities to accelerate their own independent replacement plans and encourage the implementation of rate recovery programs to assist operators with pipeline modernization. Federal assistance is also offered through programs like the Natural Gas Distribution Infrastructure Safety and Modernization Grant Program and the Methane Emissions Reduction Program, both of which have funds available for modernizing and reducing emissions from the natural gas system.

Financial aids such as these are imperative to the complete removal of cast-iron from the natural gas system, as states in the East with older natural gas infrastructure will have to make much larger investments compared to states in the West with newer infrastructure made with more reliable materials. In part due to these policies and incentives, many natural gas operators in the United States have their own pipeline replacement programs supported by federal funding assistance programs and state-approved cost recovery mechanisms. Federal leak detection and repair requirements are more clearly defined, specifically within section 114 of the PIPES Act of 2020. This section currently requires transmission and distribution operators to conduct LDAR programs which must be reviewed and approved by the relevant state authority, though a proposed rule has been submitted that would introduce additional leak survey requirements and performance standards.[140] More ambitious federal standards like this are needed to further reduce methane emissions across the entire system, especially if the current natural gas infrastructure is to be leveraged in a net-zero energy future.

## Economic Considerations of Natural Gas Decarbonization

Various market drivers will play an important role in the execution of the natural gas industry targets for mid-century. Particularly, cost efficiency will affect the rate of deployment and selection of decarbonization solutions for the natural gas industry. Supportive government incentives and funding programs have been strongly instrumental in the growth of renewable energy facilities.

Initial capital costs are not a single determining factor in the decision to deploy decarbonization pathways. Fuel production efficiency and infrastructure requirements are also important and vary with available decarbonization pathways. Some decarbonization pathways require less

[138] U.S. PHMSA. Pipeline Replacement Background. 2023. Source
[139] U.S. PHMSA. Pipeline Safety: Cast Iron Pipe (Supplementary Advisory Bulletin). 2012. Source
[140] U.S. PHMSA. Pipeline Safety: Gas Pipeline Leak Detection and Repair Proposed Rule. 2023. Source

operational energy demand, such as anaerobic digestion, but have a slower biomass conversion rate to methane than gasification with methanation. The growth of the anaerobic digestion market is attributable to the relatively passive O&M requirements, government incentives, feedstock availability, and applicability to existing natural gas infrastructure.

Alternative energy carriers can also pose indirect economic value through promoting energy diversity. Energy diversity can offset unexpected challenges that can occur with reliance on any one fuel type, promoting greater energy security by deterring unnecessary fuel supply burdens to the economy. Energy security is a present concern for the United States, with growing demands on aging infrastructure and increasing climate impacts. Recent challenges with national electricity outages further exemplify the need for energy diversity and security. Energy infrastructure which can withstand seasonal peaks and implement long-term fuel storage will be vital in the future of the United States economy. Utilizing the vast pipeline infrastructure to transport domestically produced alternative fuels also provides further energy security by reducing reliance on foreign oil imports. The increased use of domestically sourced fuels would mitigate uncertainties associated with global oil price fluctuations and foreign policies.

Alternative energy carriers can also support a circular economy model by incorporating waste streams into energy generation. These changes can lead to sustainable value chains for the energy industry and reduce emissions.

We have discussed the economic value of existing natural gas infrastructure in the future planning of the natural gas industry. These existing right-of-way and reliable delivery networks of natural gas are more economically practical starting points to incorporate the known decarbonization solutions. Furthermore, the planning of decarbonized assets will be more cost-effective if in agreement with reducing legacy cast iron and bare steel in the distribution and transmission of natural gas segments. While pipeline replacement programs exist, the rate of replacements has generally paced slower than expected. An opportunity to accelerate pipeline replacements with decarbonized assets may reduce the expected emissions with aging assets as well as create a cost synergy with new renewable energy deployments.

## The State of Renewable Energy in the Natural Gas Industry

Renewable energy is applicable to the natural gas industry either through replacing natural gas utilized in fuel production, or through displacing direct natural gas fuel applications. The production of various renewable energy sources has increased significantly over the past few decades. EIA estimates renewable energy consumption in 2022 was 13.18 quadrillion Btu, representing 13% of total U.S. energy consumption. Figure 27 shows that the majority (61%) of renewable energy was used for the electric power sector, while the industrial and transportation sectors were the next largest users. There are opportunities to increase renewable energy usage within the natural gas industry. One pathway is to utilize power-to-gas technologies that can serve as long-duration energy storage for renewable energy that is otherwise curtailed. This pathway could support the production of clean hydrogen and synthetic natural gas to decarbonize gas supplies.

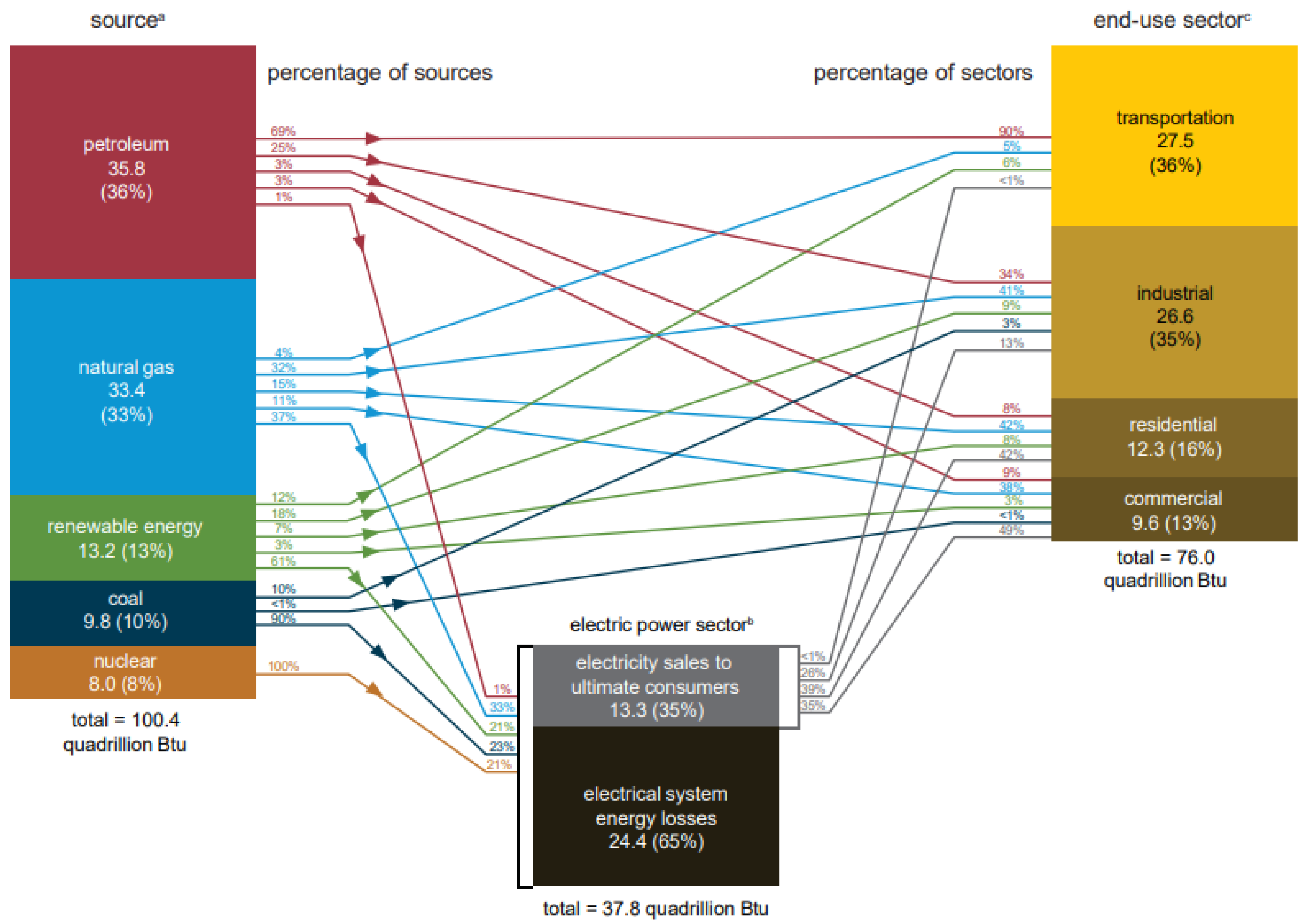


*Figure 27: 2022 U.S. energy consumption by source and sector (Source: EIA)*

Given that the availability of renewable energy varies within the US, there is a need to conduct region-specific assessments to identify the optimal energy sources and fuel pathways to achieve decarbonization in a particular area. Figures 28 and 29 show how renewable energy potentials differ by region. Figure 30 shows the hydrogen production potential using various renewable resources across the US. For example, utilizing biomass would be more suitable for the South Central region than the Pacific region. Optimizing local regional renewable resources would reduce delivery and production costs, improve system resiliency by reducing risks associated with relying on energy imports, and support economic development within the region. Regional assessments also allow for comprehensive evaluations of potential environmental impacts (e.g., land use, water resources, etc.) when planning infrastructure development. These factors will play a critical role in determining the most suitable decarbonization pathway(s) and the needed investments to accelerate deployment.

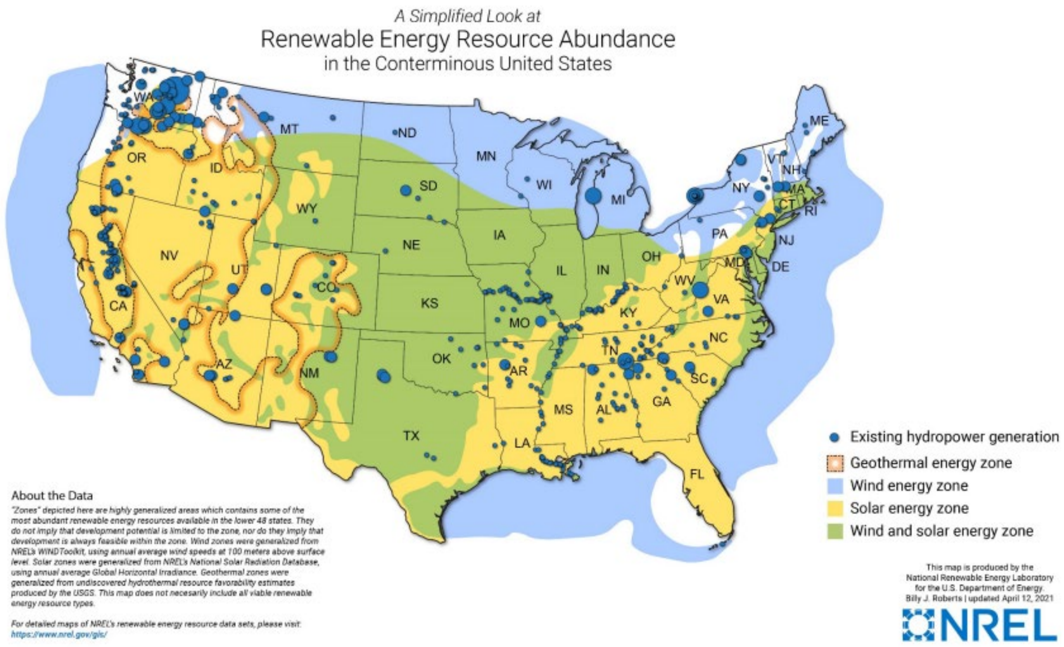


*Figure 28: Renewable energy resources across the US (Source: NREL)*

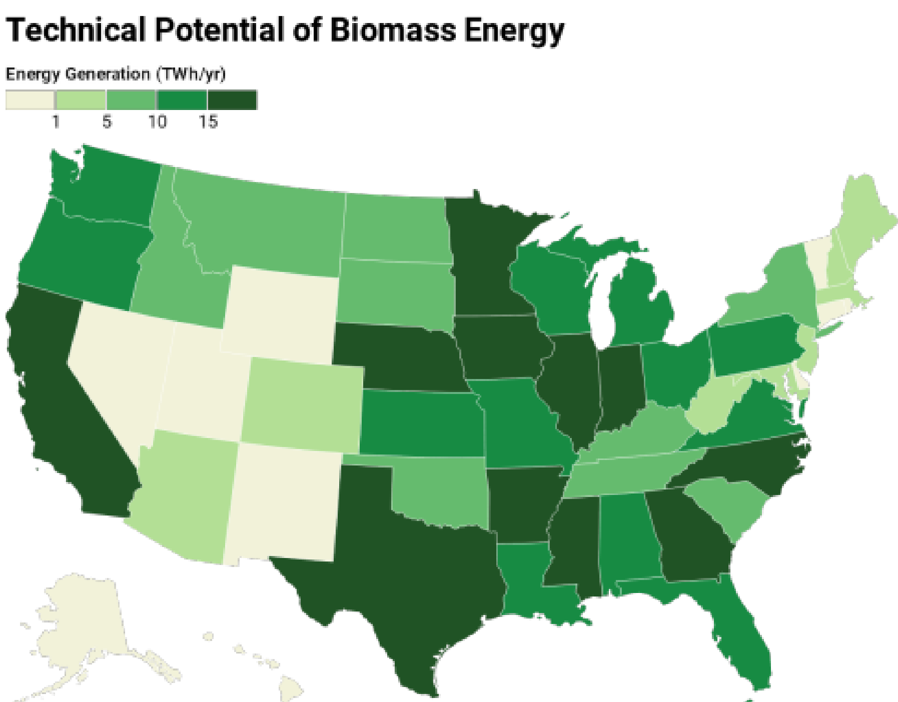


*Figure 29: Annual energy production technical potential for biomass energy (Source: U.S. Department of Energy (DOE EERE Strategic Analysis))*

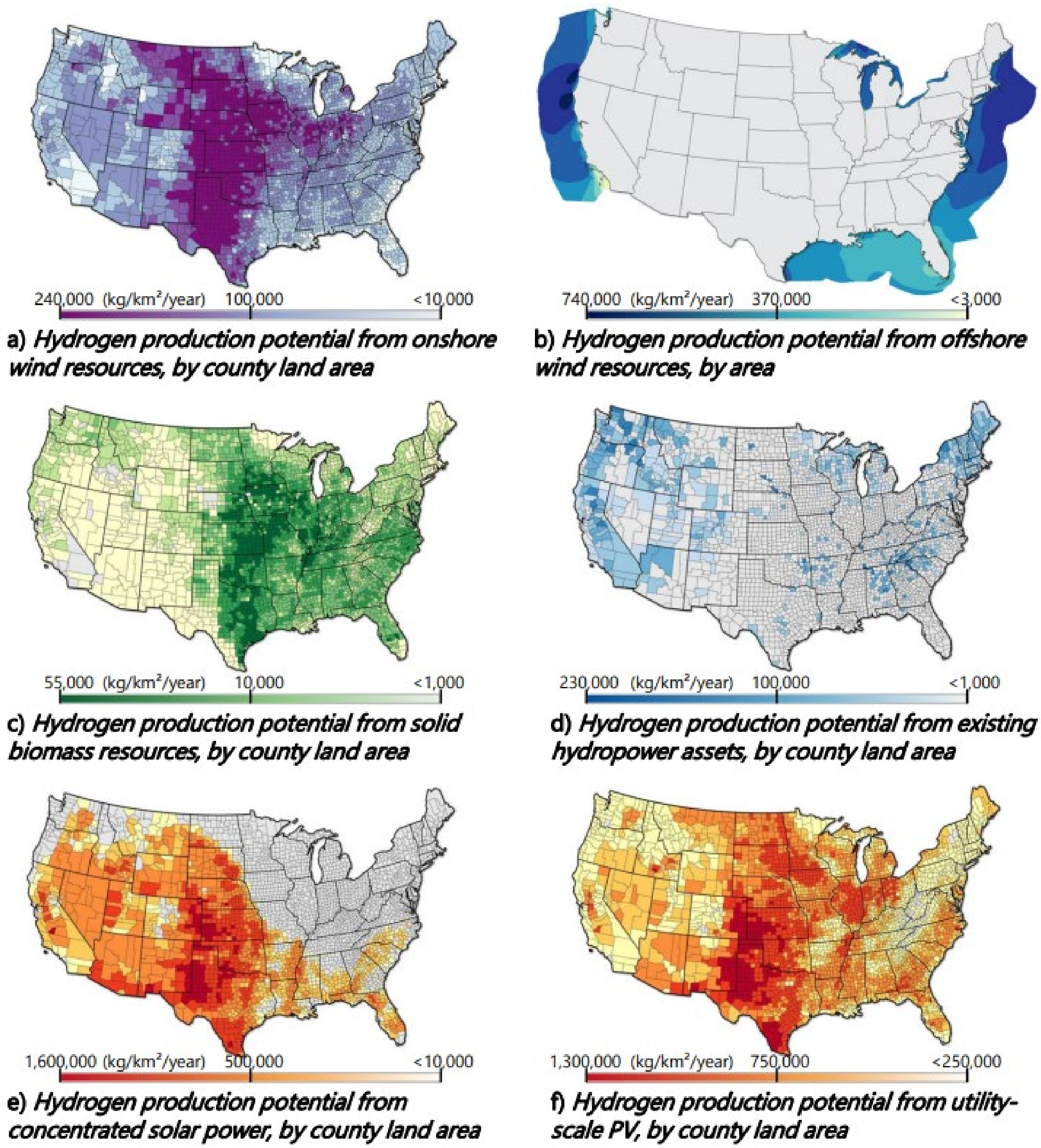


*Figure 30: Hydrogen production potential by various renewable resources (Source: US National Clean Hydrogen Strategy Roadmap)*

# Conclusions

The demand for natural gas across various sectors is significant in the US economy today. As energy demand grows, the historically developed natural gas infrastructure will continue to play an important role in the planning of future energy systems. Herein, we have discussed the value of the natural gas assets in the US, as well as various elements influential to the execution of the natural gas industry's mid-century decarbonization targets. Decarbonization solutions that can leverage existing infrastructure include RNG, SNG, Hydrogen, and CCUS.

RNG and SNG, being pipeline-quality natural gas, easily integrate into the current infrastructure with minimal adjustments. Ensuring that lifecycle CO2 emissions of NG and SNG are minimized, makes them instrumental in achieving our decarbonization goals. This circular approach harnesses methane from waste for energy, reducing emissions and supporting a sustainable energy economy. Repurposing natural gas pipelines for hydrogen transport reduces emissions, energy delivery costs, and capital expenses. Several pipelines have already undergone this conversion to 100% hydrogen, promoting a low-carbon fuel supply through existing assets. Repurposing pipelines for CO2 transport, with considerations for material compatibility and safety, can also reduce construction costs and support a circular economy.

Furthermore, improving emissions detection, quantification, and measurement, as well as replacing aging infrastructure with modern materials, can further reduce emissions. These pathways, along with integrating emerging low-carbon fuels, offer opportunities for natural gas players to decarbonize and enhance the energy system's resilience and cost-effectiveness.

In supplement to this paper, NZIP is in the process of developing an interactive infrastructure map, inclusive of three dataset categories: existing infrastructure, decarbonization potential, and energy resiliency and accessibility. The findings expressed in this paper, combined with the interactive infrastructure map will be utilized to develop a comprehensive analysis of the decarbonization pathways and their suitability in different regions across the country. Future regional case studies to be published in 2024 and 2025 will provide decarbonization pathway recommendations by considering the unique infrastructure, renewable energy resources, and policies, within a region. As policy can be a key driver for the development and implementation of national decarbonization strategies, NZIP will also provide a holistic analysis of federal and state-level regulation related to the current and possible future uses of natural gas infrastructure. This analysis will provide policy recommendations for leveraging current natural gas infrastructure in a socially responsible, net-zero energy system that benefits all stakeholders equitably.

**END OF REPORT**