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Reliable Affordable Infrastructure for Secure Energy

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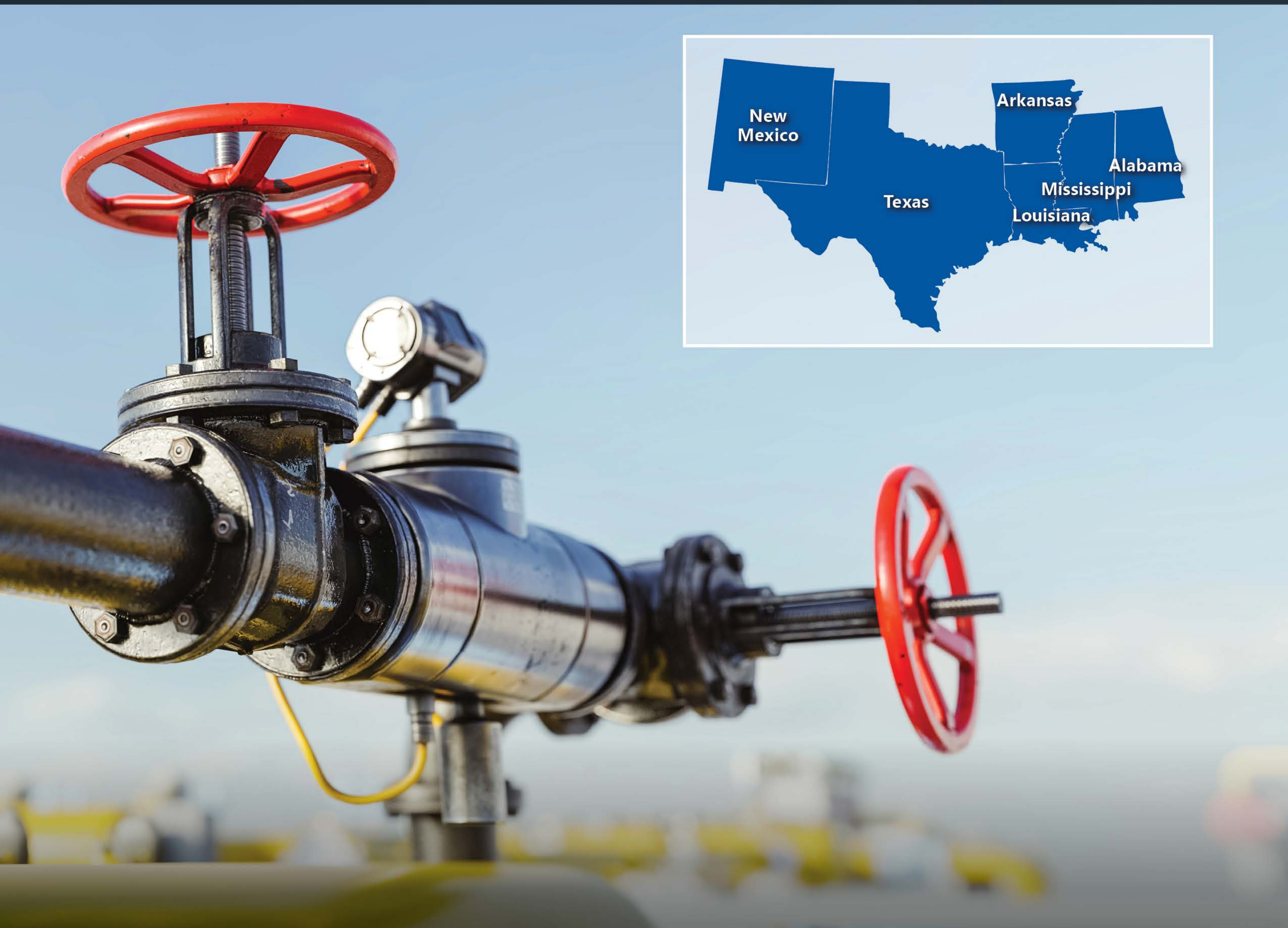

CASE STUDY

Utilizing Gulf Coast Natural Gas Infrastructure for Emerging Fuels

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Glossary

Term	Definition
Autothermal Reforming (ATR)	A hydrogen production method that involves natural gas reacting with steam and air to produce a gas mix that contains hydrogen, carbon monoxide, and carbon dioxide. The carbon monoxide in the gas mix is then converted to produce more hydrogen and carbon dioxide. The hydrogen is purified for use.
Business as Usual (BAU)	OL-NEMS scenarios that represent a baseline for emerging fuels adoption, assuming no significant changes in current policies, technologies, or behaviors. These include: 1) Reference case, 2) Low Oil & Gas Supply case, 3) High Economic Growth and High-Zero-Carbon Technology. See "Description of Business-as-Usual (BAU) Scenarios" section for scenario descriptions.
Cost-Benefit Analysis (CBA)	Analysis to identify the most cost-effective technology pathways to meet the energy demand and manage emissions in the Gulf Coast, by leveraging cost, emission and demand findings.
Capacity	Annual facility production rate.
Capacity Factor (CF)	Percent of the year facility produces fuel.
Carbon Intensity (CI)	A quantification of the GHG emissions impact of particular fuel pathway; from production to end-use delivery. CI scores are often reported on a kg CO_2eq/ energy content fuel produced.
Carbon Capture, Utilization, & Storage (CCUS)	Recovery of CO_2 from industrial or natural sources, utilization for the production of fuels, and storage into geological or synthetic storage
Emerging Fuels	Low-carbon fuels that have the potential to replace conventional natural gas. For this case study, the emerging fuels considered are H_2, RNG, and SNG.

Greenhouse Gas (GHG)	Greenhouse gases trap heat in the atmosphere. These gases include carbon dioxide, methane, nitrous oxide, and fluorinated gases).
Hydrogen (H_2)	Low density fuel, able to be produced from several renewable sources and can be blended into NG systems
Lifecycle Analysis (LCA)	Estimation of fuel specific GHG emissions impact
Low Carbon (LowC)	Technologies which offer carbon emission reductions in comparison to traditional fossil fuel- dependent technologies and fuel pathways.
Municipal Solid Waste (MSW); source separated	Discarded waste originating from mixed sources (i.e., households, commercial businesses) including organics such as yard trimmings, food waste which can be separated from non-organics such as plastics, waste electronics.
Natural Gas Combined Cycle (NGCC)	A gas turbine generates electricity, and its waste heat is used to produce steam, which drives a steam turbine to generate additional electricity.
OnLocation's National Energy Modeling System (OL-NEMS)	A custom version of EIA's NEMS developed to model long-term energy markets and associated climate impacts with specific fuel pathways, by integrating lifecycle, economic, and market level data.
Renewable Natural Gas (RNG)	Biomass-derived methane produced via micro-organisms or thermal processes, compositionally similar to NG and blendable into NG systems.
Steam Methane Reforming (SMR)	A hydrogen production method that involves reacting natural gas with high-temperature steam and a catalyst to produce hydrogen, carbon monoxide, and carbon dioxide; the carbon monoxide then reacts with steam to yield more hydrogen and carbon dioxide, after which impurities including carbon dioxide are separated to purify the hydrogen. This hydrogen production method is currently the most common.

Synthetic Natural Gas (SNG)	Methane produced via electrolysis with methanation processes, compositionally similar to NG and can be blended into NG systems.
Technoeconomic Analysis (TEA)	Cost analysis of fuel pathway

Introduction

In the midst of evolving energy infrastructure and a growing emphasis on reliable and secure domestic energy, sustainable emerging fuels such as hydrogen (H_2), renewable natural gas (RNG), and synthetic natural gas (SNG) stand out as potential solutions to further diversify the nation's energy portfolio, enhance energy security, and reduce the emissions impacts of the energy supply.

Given that infrastructure, resources and end-users significantly differ by region, RAISE is conducting regional analyses to identify the most promising emerging fuel(s) within each of the five major U.S. regions, as defined by the Petroleum Administration for Defense Districts (PADD), to assess how natural gas infrastructure could facilitate the adoption of emerging fuels (**Figure 1**). The PADD regions were chosen to reflect key differences in natural gas and electricity supply relevant to infrastructure location.

This report, the first of a series of case studies covering these five regions, focuses on the Gulf Coast region, which encompasses Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas.

Figure 1. Five U.S. regions, as defined by the Petroleum Administration for Defense Districts (PADD)

The Gulf Coast has exceptional natural gas production and extensive delivery infrastructure, with Texas and Louisiana representing some of the greatest natural gas consuming and producing states. The region has considerable renewable energy and geothermal potential, which can facilitate the production of lower-carbon fuels to enhance its energy mix and diversify fuel options.

Energy markets are dependent on a complex set of factors. While this study cannot analyze all market influences, the analysis here considers major contributing factors that will significantly impact the adoption of emerging fuels in the Gulf Coast region. The analysis methods utilized to evaluate resource availability, projected costs, and associated emissions are discussed further in the body of this report. The emerging fuels considered in this study, H_2, RNG, and SNG, are ideally delivered using a mix of existing natural gas pipelines or newly constructed pipelines to optimally manage delivery costs and efficiently meet demand markets.

This report explores the integration of emerging fuels at both conservative and optimistic adoption rates using an average overall blending target as some end-uses can accept higher blends (compared to others). Based on the analyses' results and the region's regulatory landscape, this report also outlines opportunities and recommendations such as policy incentives and technological advancements that could support the adoption of emerging fuels in the Gulf Coast region.

Emerging Fuel Pathways Considered

This section provides brief summaries of the various emerging fuel pathways considered, including the case identifiers of the pathways that will be used throughout the text and visual summaries. Eight pathways are associated with H_2 production, four are associated with RNG production, and four are associated with SNG production. The fuel pathways considered are summarized in **Table 1**. Further detailed descriptions of these pathways are provided in the appendices.

Table 1. Fuel pathways considered in this case study

H_2 Cases	**SMR**		**ATR**		**Plasma Pyrolysis**	**Electrolysis**
	with CCUS	*without CCUS*	*with CCUS*	*without CCUS*		
Identifier	H2-1, H2-5	H2-3	H2-2, H2-6	H2-4	H2-7	H2-8

RNG Cases	**MSW**	**Biomass**		**LFG**
		Forest	Agriculture	

Identifier	RNG-1	RNG-2	RNG-3	RNG-4

SNG Cases	NGCC Power Plant	Cement Plant	Steel Plant	Ethanol Plant
Identifier	SNG-1	SNG-2	SNG-3	SNG-4

Hydrogen Pathways (H_2-1 through H_2-8)

- H2-1 & H2-2: Natural gas reforming (steam methane and autothermal) with carbon capture and storage (CCS), achieving 94-96% capture rates
- H2-3 & H2-4: Similar reforming processes using RNG from landfill gas, without CCS
- H2-5 & H2-6: RNG reforming with CCS at the same high capture rates
- H2-7: Plasma pyrolysis of natural gas producing H_2 and solid carbon with minimal CO_2 emissions
- H2-8: Electrolysis using six different low-carbon electricity sources (solar, wind, nuclear, hydro, biomass, and combined solar/wind with battery storage)

Renewable Natural Gas Pathways (RNG-1 through RNG-4)

- RNG-1: Gasification of municipal solid waste to produce synthetic natural gas
- RNG-2: Gasification of woody biomass (trees, shrubs, leaves)
- RNG-3: Gasification of herbaceous biomass (grasses, grains)
- RNG-4: Upgrading landfill gas through anaerobic digestion

Synthetic Natural Gas Pathways (SNG-1 through SNG-4)

All pathways combine captured CO_2 with electrolytic H_2 to produce synthetic natural gas:

- SNG-1: CO_2 from natural gas power plants
- SNG-2: CO_2 from cement plants
- SNG-3: CO_2 from steel plants (limited regional availability)

- SNG-4: High-purity CO_2 from ethanol fermentation

Each pathway offers different approaches to producing low-carbon alternatives to conventional fuels, with varying infrastructure requirements and regional availability constraints.

Case Study Approach

This section outlines the comprehensive analytical approach undertaken in this study, as illustrated in **Figure 2**, integrating technical, economic, and environmental considerations to evaluate the H_2, RNG, and SNG pathways. Three core analyses were performed:

1) Technoeconomic Analysis (TEA)

The TEA assesses the comparative economic viability of the H_2, RNG, and SNG pathways.

2) Lifecycle Analysis (LCA)

The LCA quantifies the environmental impacts across the entire life cycle of the energy systems, considering raw material extraction, manufacturing, operation, and disposal, as inputs to estimate greenhouse gas emissions.

3) Regional Fuel Pathway Optimization Analysis

The optimization analysis assesses the broader system-level interactions and trade-offs under various scenarios, including business as usual (BAU) scenarios, integrating TEA results and policy and market assumptions to determine optimal technology deployment strategies, energy supply mixes, and associated costs.

These analyses collectively inform the cost-benefit analysis (CBA), which evaluates the total costs against the total benefits of the various pathways, providing a holistic perspective for decision-making. The following sections summarize the methodologies and assumptions used for the optimization model, TEA, LCA, and CBA.

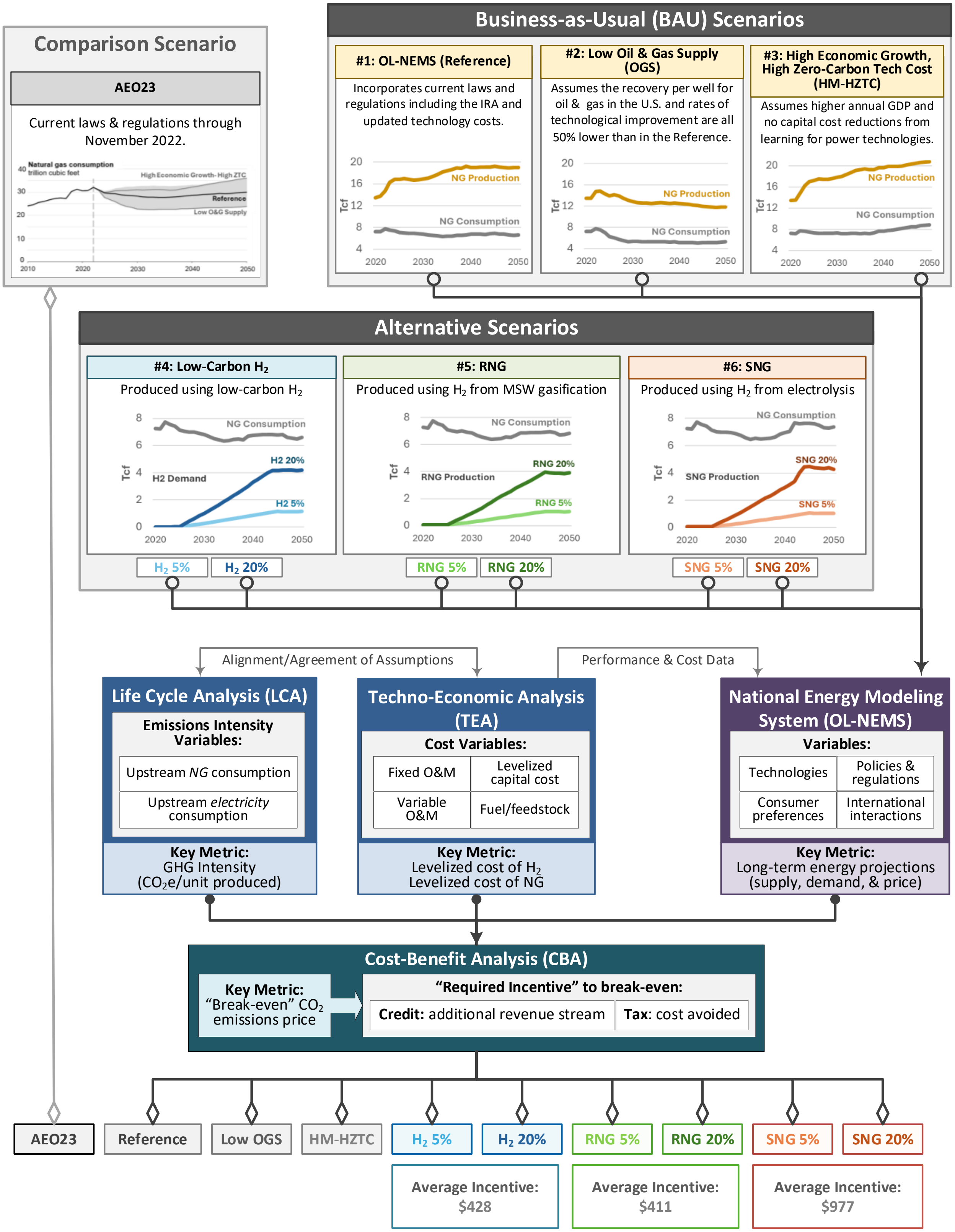


Figure 2. Integrated analysis of cost, emissions, and deployment strategies for H_2, RNG, and SNG pathways.

Optimization Model

Model Description

The National Energy Modeling System (NEMS) is developed and maintained by the Energy Information Administration (EIA). NEMS is an energy-economy modeled representation of the U.S. energy market for the period extending from the base year to 2050. It produces an optimized solution with energy supply always meeting demand in the U.S. energy markets for each year of the model run. The model outputs include projections of energy production, imports, exports, conversion, consumption, and the prices of energy carriers, subject to a number of assumptions. These assumptions encompass macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics ("The National Energy Modeling System: An Overview" 2023).

The EIA Annual Energy Outlook (AEO) presents long-term projections of energy supply, demand, and prices, based on NEMS results annually. Though EIA did not release an AEO in 2024, there were many changes underway and expected in the U.S. energy system for technologies, policies and regulations, consumer preferences, and international interactions. As a result, OnLocation produced an energy system projection to 2050 with the application of their customized version of NEMS (OL-NEMS). OL-NEMS includes all the Energy Supply, Energy Conversion, and Energy Demand modules in NEMS with enhancements and additional modules for H_2 supply and critical materials demand as shown in **Figure 3**.

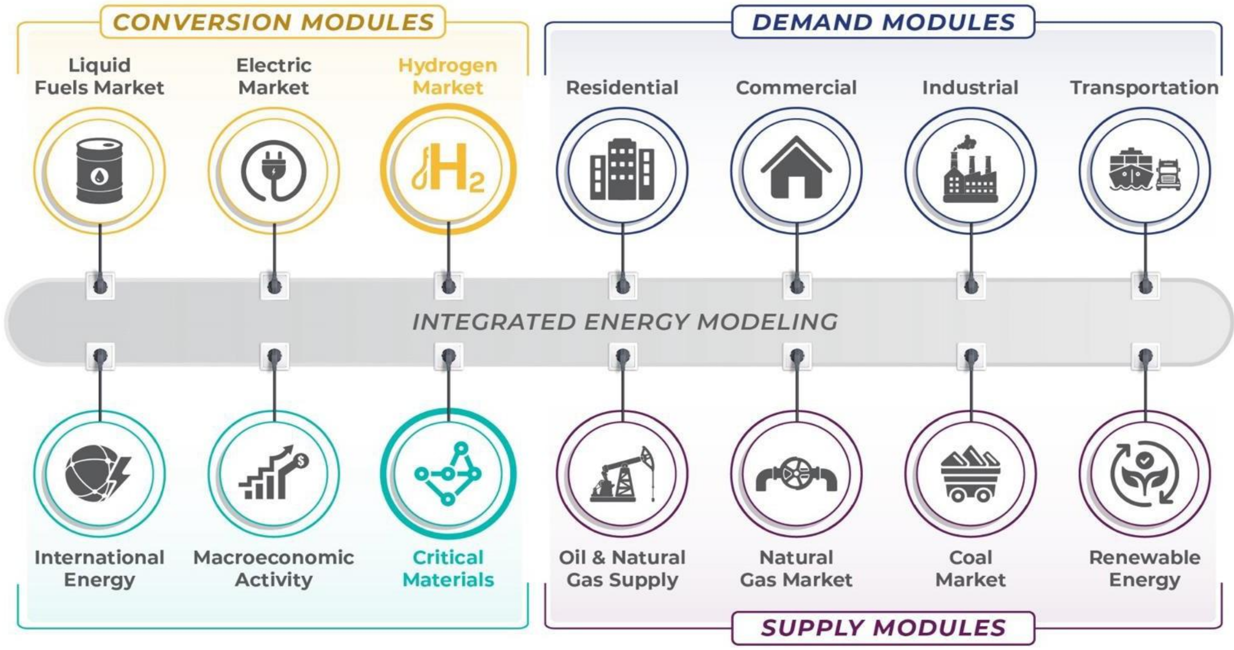


Figure 3. OL-NEMS modules (used with permission from OnLocation)

This case study leveraged 2023 release (AEO23) as one of the business-as-usual scenarios along with OL-NEMS modeling to evaluate a range of potential energy demand scenarios, comparing proactive, incentive-driven cases with favorable demand conditions to more passive scenarios characterized by market constraints and a lack of additional regulatory support. The results provide insights into how emerging fuels can be scaled under various market conditions in the Gulf Coast region.

Regional Inputs

OL-NEMS is a national model that considers interactions between regions as a critical piece for deriving the most accurate forecasts for energy. However, this study limits the influence of surrounding regions within selected modules to focus specifically on the Gulf Coast. This approach allowed for isolation and analysis of the region's supply and demand dynamics, providing a clearer view of the potential for emerging fuel adoption in the Gulf Coast.

Since this case study's region (PADD's Region 3 in **Figure 4**) is not directly used in OL-NEMS, module adjustments were made to represent gas and electricity demand and prices in the Gulf Coast region. These region-specific adjustments resolve the regionality differences between OL-NEMS and PADD. **Appendix B** contains information on the adjustments made.

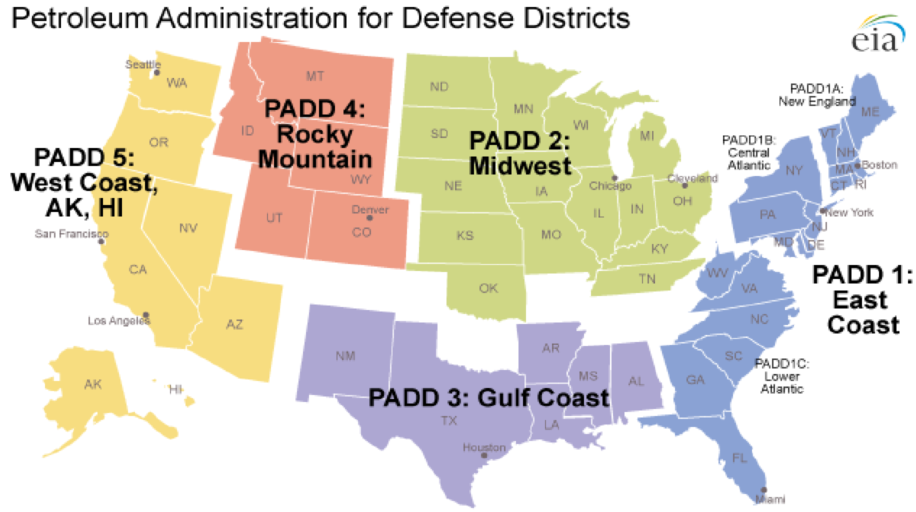


Figure 4. Gulf Coast Case Study region (PADD 3) (Source: EIA)

Description of Business-as-Usual (BAU) Scenarios

To account for different economic conditions, the modeling analysis considers four Business-as-Usual scenarios. The **AEO23 Reference Case** provides a baseline assessment of U.S. energy markets through 2050 under November 2022 laws and evolutionary technology assumptions. The **OL-NEMS 2024 Reference Case** builds on AEO23 but incorporates updated EPA standards, state policies, comprehensive IRA provisions (including clean fuel and H_2 tax credits), lower renewable technology costs, and higher electricity demand from data centers, resulting in faster fossil fuel phase-out. The **Low Oil & Gas Supply** assumes 50% lower recovery rates for tight oil/gas, reduced undiscovered resources, and slower technological improvement, making emerging fuels more competitive. The **High Economic Growth-High Zero-Carbon Technology Cost** combines higher GDP growth (2.3% annually) with stagnant zero-carbon technology costs, creating challenging conditions for emerging fuel adoption. **Table 2** summarizes the four BAU scenarios used to model the economic impacts of emerging fuels use on the energy economy, and the anticipated impacts on the adoption of emerging fuels.

Table 2. Summary of BAU scenarios

BAU Scenario	Description	Anticipated Impact
#1: AEO23 Reference Case	Current laws and regulations impact (2022) on energy market growth through 2050	**Neutral**
#2: OL-NEMS 2024	Includes technology cost updates and	**Supportive**

Reference Case	IRA and other policies implemented since AEO23 was released	
#3: Low Oil/ Gas Supply	Assumes high success of renewables-based technologies adoption	**Supportive**
#4: High Economic Growth-High Zero-Carbon Technology	Assumes higher natural gas use but with a restricted ability to reduce carbon emissions	**Unsupportive**

Pathways Evaluation Inputs and Assumptions

Fuel-specific costs and emissions, as well as regional feedstock availability, are represented by the TEA, LCA, and resource availability analyses. **Figure 5** visualizes the summarized modeling inputs used to drive the cost-benefit analysis. This section discusses the key assumptions and methods of the TEA, LCA, and resource availability analyses.

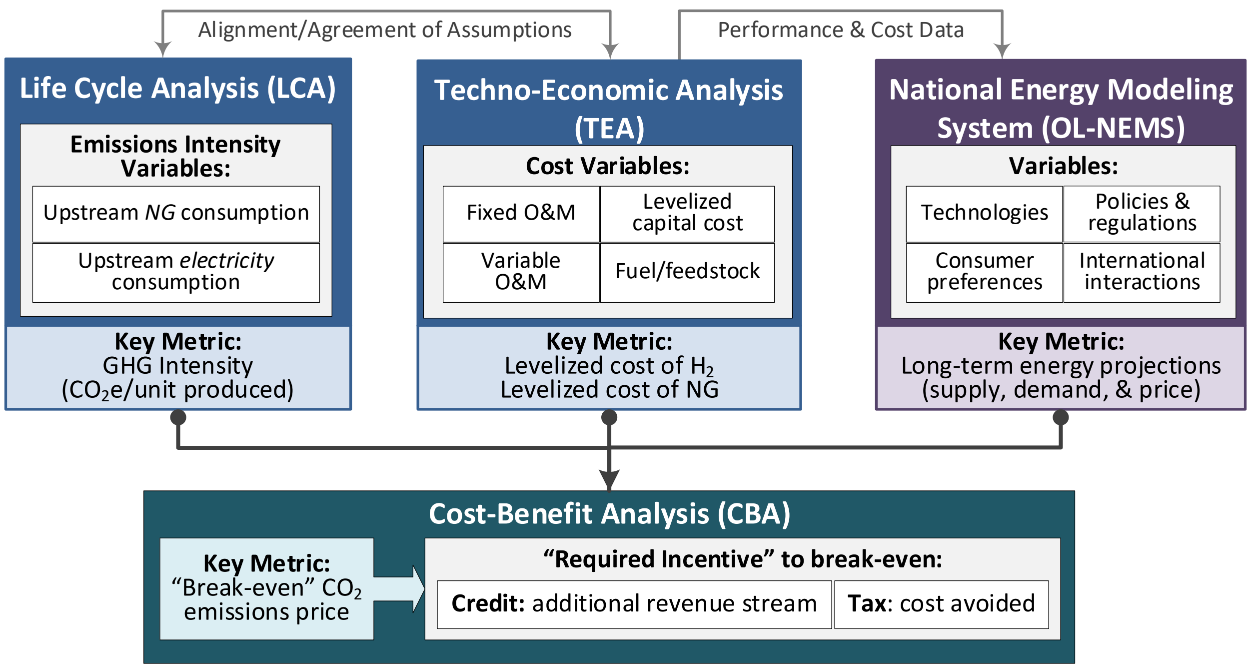


Figure 5. Summary of key TEA, LCA, and resource availability inputs used to inform the cost-benefit analysis.

TEA: Methodology and Assumptions

The TEA largely follows the National Energy Technology Laboratory (NETL)'s Quality Guidelines for Energy System Studies (QGESS) method to calculate the fuel-specific levelized cost, which considers the revenue required per unit of product produced during the plant's operational life to meet all capital and operational costs (i.e., $/kg H_2, $/MMBtu RNG, $/MMBtu SNG). Levelized costs are estimated as a summation of capital, operational, and facility maintenance costs; each of which is calculated based on reported facility-specific reference capacities, capacity factors, referenced fixed costs, and time normalized accordingly. Assumptions and more detailed information on the TEA methodologies can be found in **Appendix C**.

Default QGESS assumptions were used with modifications for H_2 -specific financial parameters and CO_2 transport and storage costs integrated into variable operations and maintenance (O&M) costs.

The major differences between the H_2 cases assessed in this study reflect production technologies utilized, and the price differences of each renewable electricity source considered. For H_2 produced via electrolysis (case H2-8), six low-carbon electricity sources were considered, with solar and biomass electricity representing the lowest and highest cost sources, respectively (U.S Energy Information Agency 2022). While this study considers state-level differences in renewable electricity sources for the H2-8 pathway, a uniform regional RNG price of $22/MMBtu; (Guidehouse and Coalition for Renewable Natural Gas 2024) is assumed for producing H_2 (i.e., cases H_2-3 to H_2-6). This assumed RNG cost generally aligns with other similar studies, such as the 2019 ICF–AGF study (ICF 2019). Note that RNG can be more expensive when produced with dairy digesters, which is a production pathway not included in this study.

Municipal solid waste (MSW) was assumed to be freely accessible and co-located with a gasification facility in the considered RNG cases. For LFG feedstock, it was assumed that it can be obtained at 10 percent of the levelized cost of RNG production, representing a 10 percent royalty on RNG sales revenue. Calculated operating costs and utilized capital costs for SNG production incorporated several referenced assumptions, including upstream feedstock-specific handling, and auxiliary and process demand assumptions.

LCA: Methodology and Assumptions

The LCA estimates GHG intensity for fuel production pathways across the PADD Gulf Coast region, following DOE's Hydrogen Shot study methodology (Lewis et al. 2022). Two open-source tools are used across this study to provide LCA results. First, the Open Hydrogen Initiative (OHI) toolkit provides default parameters for H_2 pathways, except for low-carbon H_2 production cases requiring RNG (e.g., RNG-fed ATR with CCS) where upstream natural gas and electricity inputs needed to be modified for state or regional-level consistency. Next, an openLCA model, developed by NETL and informed by the TEA results, is used as a reference when needed for input stream flowrates in the OHI toolkit. This model helped define OHI inputs for electricity, natural gas, and water input flowrates of SNG and RNG production pathways to capture their unique characteristics. Further details on the LCA modeling approach can be found in **Appendix D**.

Regional variations in upstream natural gas GHG intensity are based on NETL's baseline study (Khutal et al., 2024), which reports 0.56% average methane leakage rates across U.S. techno-basins and includes regional emissions estimates with uncertainty ranges. NETL delivery region data was transformed to PADD regions using state-level consumption data from EIA (U.S Energy Information Agency 2024). Similarly, upstream electricity GHG intensity variations were derived by adjusting FERC regional data to PADD boundaries using state electricity consumption data.

Regional GHG intensity variations are primarily driven by natural gas and electricity consumption inputs, while system-level parameters (CCS efficiency, process efficiency, production pathway, grid decarbonization, by-product management, and methane leakage rates) remain location-independent.

All H_2 production pathways use assumptions within the OHI toolkit specific to their individual pathway. For example, the inputs required for plasma pyrolysis in the OHI toolkit are obtained by modifying the methane pyrolysis scenario in openLCA. The study had cradle-to-gate scope, and the primary functional unit of this study was 1 kg of H_2 produced, >99.9 vol%, 6.38 MPa. However, as the plasma pyrolysis process produces several co-products, the functional unit also corresponds to co-products of 3.54 kg of carbon black and 33.7 kg of superheated steam (at 399°C and 3.1 MPa), as well as a waste product of 0.0590 kg of coke. See **Appendix D** for further details on the LCA inputs and outputs.

CBA: Methodology and Assumptions

The CBA synthesizes the results from the OL-NEMS model, TEA, and LCA to identify the most viable technology pathway to meet the energy demand and manage emissions. The CBA adds the key metric of a “Required Incentive” calculation for each fuel pathway technology, a concept exemplified by the recent federal carbon tax credits, 45Q and 45V (U.S. Congress, n.d.). These incentives represent the economic offset required for the given fuel to reach cost-parity with natural gas. Additionally, the calculated required incentives can inform stakeholders of the range of economic stimuli necessary to promote the adoption of some of the technologies being explored by this study. This incentive is essentially a “break-even” CO_2 emissions price, which can be interpreted either as a cost avoided in the case of a tax, or an additional revenue stream in the case of a credit. The incentives were calculated using the following equation:

$$\text{Required Incentive} = \frac{\text{LC}_{\text{Renew}} - \text{LC}_{\text{NG}}}{\text{CI}_{\text{NG}} - \text{CI}_{\text{Renew}}}$$

where LC is the levelized cost of the renewable fuel or natural gas respectively, in $/MMBtu, and CI is the carbon intensity of the fuel in tons of CO_2/MMBtu. These numbers were all calculated based on the mass and higher heating values (HHV) of the fuels in question, which were assumed to be 22,500 Btu/lb for natural gas and all similar fuels and 61,084 Btu/lb for H_2 (The Engineering ToolBox, 2005). See **Appendix E** for further details on the CBA methodology and assumptions.

Resource Availability: Methodology and Assumptions

To assess potential resources available resources and feedstock to support production of H_2, RNG, and SNG in the Gulf Coast region, a comprehensive data collection effort focused on key feedstocks and energy sources was conducted. These feedstocks included agriculture and forest residues, MSW, natural gas reserves, and landfill gas. Data was sourced from a range of federal agencies to ensure accuracy and consistency. These sources include Environmental Protection Agency, U.S. Department of Agriculture, EIA, NETL, and DOE’s Bioenergy Technology Office’s 2023 Billion Ton Report. This dataset provided the foundation for evaluating the feasibility and scalability of H_2, RNG, and SNG in the Gulf Coast.

Landfill gas assumptions were calculated from the EPA Landfill Methane Operational Project (LMOP) database. While availability of landfill gas has been estimated by EPA, competing uses such as onsite CNG/power utilization were not considered. The analysis did not consider competing feedstock uses such as composting or use for liquid advanced biofuel production.

Blending Range Assumptions

To explore conservative and optimistic low-carbon fuels adoption scenarios, this study considers the integration of 5 and 20 vol% (by volume) H_2 and RNG/SNG blends into the Gulf Coast natural gas systems. Some end uses (e.g., residential) may be able to accept higher H_2 blends, while other end uses (e.g., LNG facilities, CNG stations) may be unable to accept H_2 in their gas supplies. Additionally, material compatibility constraints may prevent H_2 blending percentages greater than 20 vol%. Although RNG and SNG do not have the same end-use and material compatibility challenges, a 20 vol% blending target is also assumed to align with goals announced by leading natural gas operators. Therefore, the target 5 and 20 vol% blending rates are assumed to represent average system-wide targets.

To avoid abrupt shocks to the energy system, these blending rates are assumed to be gradually achieved over a period of 20 years, starting in 2026 and reaching the maximum value by 2045. The rates of increase were 0.25 vol% and 1 vol% per year for the 5 vol% and 20 vol% blending cases, respectively, as shown in **Figure 6**. It is assumed blending is to occur via policy mandate and is not evaluated economically.

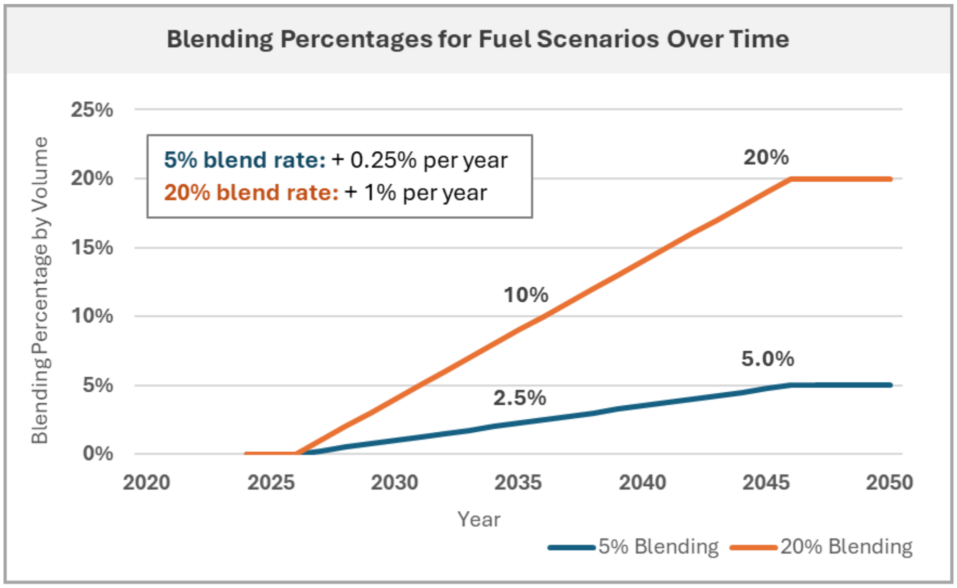


Figure 6. Assumed natural gas blending percentages over time

Case Study Findings

This section summarizes the findings of the estimated end-use demand, resource availability analysis, TEA, LCA, and CBA described in the Case Study Approach previous sections.

Estimated End-Use Demand in the Region

Given that only H_2 and natural gas demand data are available for all states in the region. RNG and SNG are assumed to share demand with traditional natural gas for the purposes of this study.

Natural Gas Demand

Natural gas demand across the region is closely tied to supply levels, with prices generally moving inversely to supply and demand. Texas has the lowest average natural gas price at approximately $2.47/MCF, while Arkansas faces the highest prices (over $9/MCF) due to limited infrastructure and reliance on imports.

With both competitive pricing and robust production, Texas leads regional natural gas demand (**Figure 7**). Across the Gulf Coast, existing demand is heavily concentrated in industrial applications and power generation, particularly in Texas and Louisiana. Power generation remains a key use of natural gas in all Gulf Coast states. As of 2023, states like Louisiana and Mississippi have the lowest renewable electricity consumption in the region, suggesting continued reliance on natural gas for electricity generation in the near future.

State-level demand estimates are based on overall 2023 natural gas consumption rates (U.S. Energy Information Administration, n.d.-a) and are visualized in **Figure 7**.

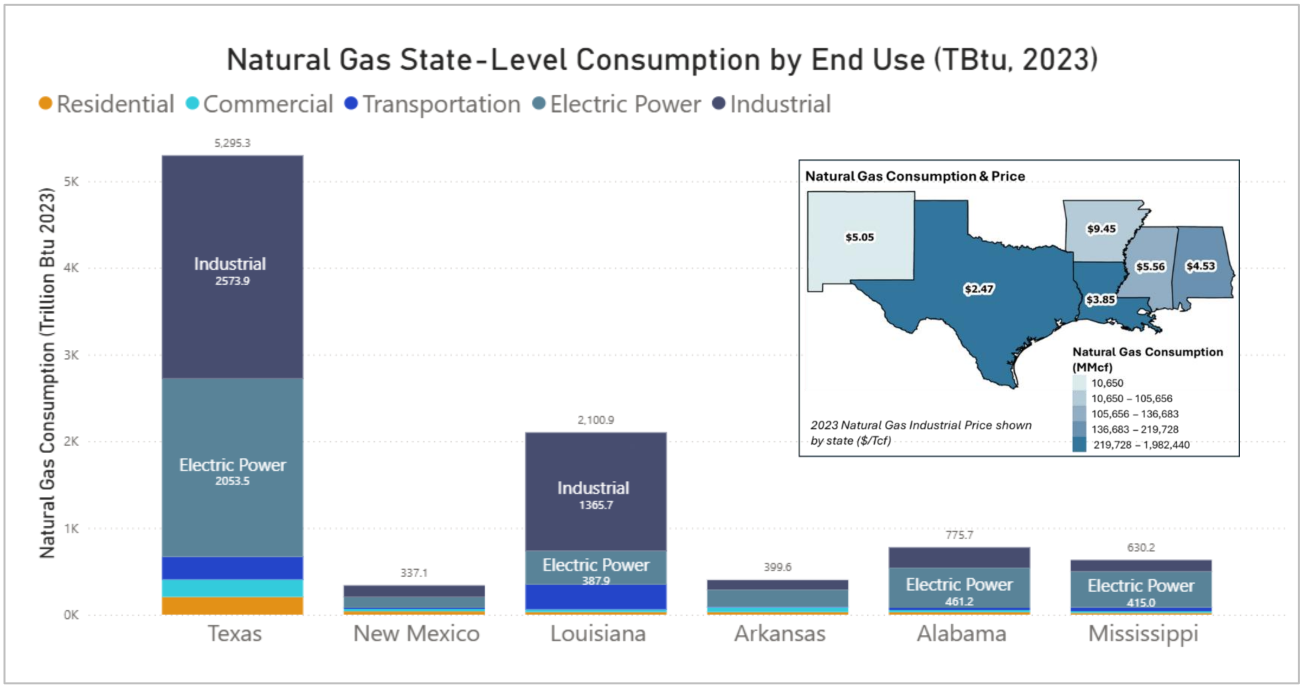


Figure 7. Natural gas state-level consumption by end-use sector

Figure 8 shows the percentage of total energy consumption represented by natural gas end users by sector type in each Gulf Coast state.

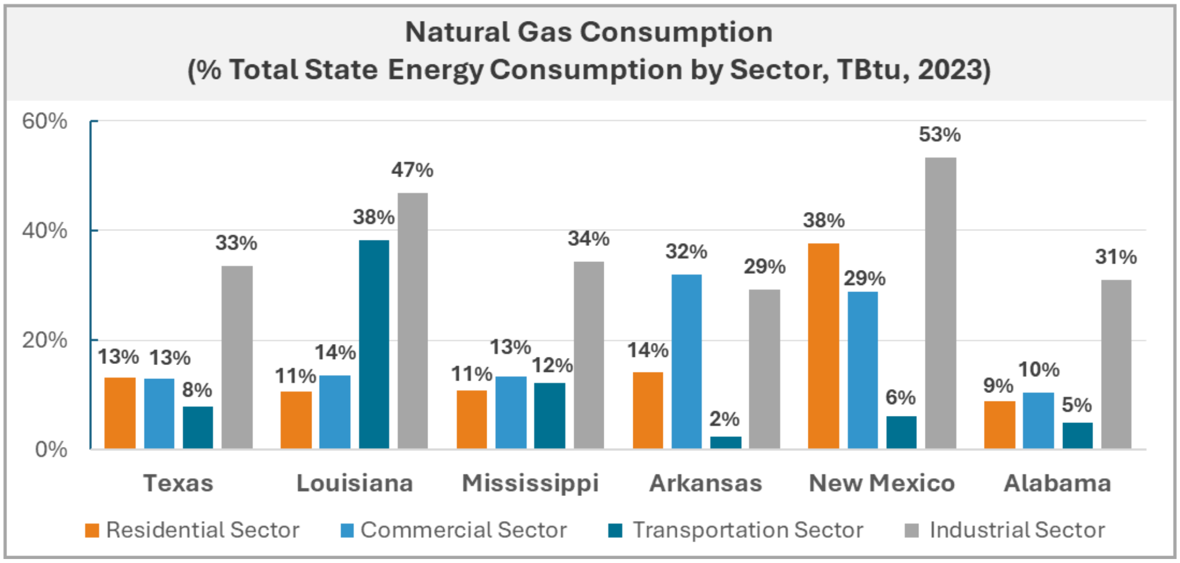


Figure 8. Natural gas consumption (% total state-level energy consumption)

Although Texas and Louisiana comprise the majority of industrial end-use consumption of natural gas in the Gulf Coast, New Mexico and Louisiana's industrial end users rely relatively more on natural gas.

Natural gas consumption represents approximately 20% of combined residential and commercial energy consumption in each Gulf Coast state, with the exception of New Mexico and Arkansas, which rely significantly more on natural gas in these sectors. Although residential and commercial consumption represents a smaller portion of total natural gas demand in the Gulf Coast region, a noticeable increase in winter consumption was observed in 2024 due to more severe cold weather conditions.

As seen in **Figure 7** and **Figure 8**, the Gulf Coast transportation sector is most reliant on natural gas in Louisiana and Mississippi. However, future demand is expected to grow in Texas, Louisiana, and Alabama. States with established CNG fueling stations, such as Texas, New Mexico, and Louisiana, are better positioned to meet the local transportation sector's natural gas demand.

The Gulf Coast states demonstrate strong overall energy consumption in the industrial and transportation sectors, with Texas, Louisiana, and Alabama making up the majority of the demand. While this study assumes RNG and SNG demand to align with current natural gas demand and be influenced by available incentives, actual demand will likely depend on end users' interest in decarbonizing with RNG or SNG blends.

H_2 Demand

Due to the high concentration of ammonia production facilities and petroleum refineries, H_2 demand is currently primarily in Texas and Louisiana. Each state had an estimated demand of over 300 petajoules in 2024. **Figure 9** illustrates the 2024 state-level H_2 demand in the Gulf Coast based on data from Evolved Energy Research's Annual Decarbonization Perspective report (Jones, R.A., Haley, B., et al. 2024). It highlights the regional and sector distribution of H_2 consumption and the importance of Texas and Louisiana in the H_2 market.

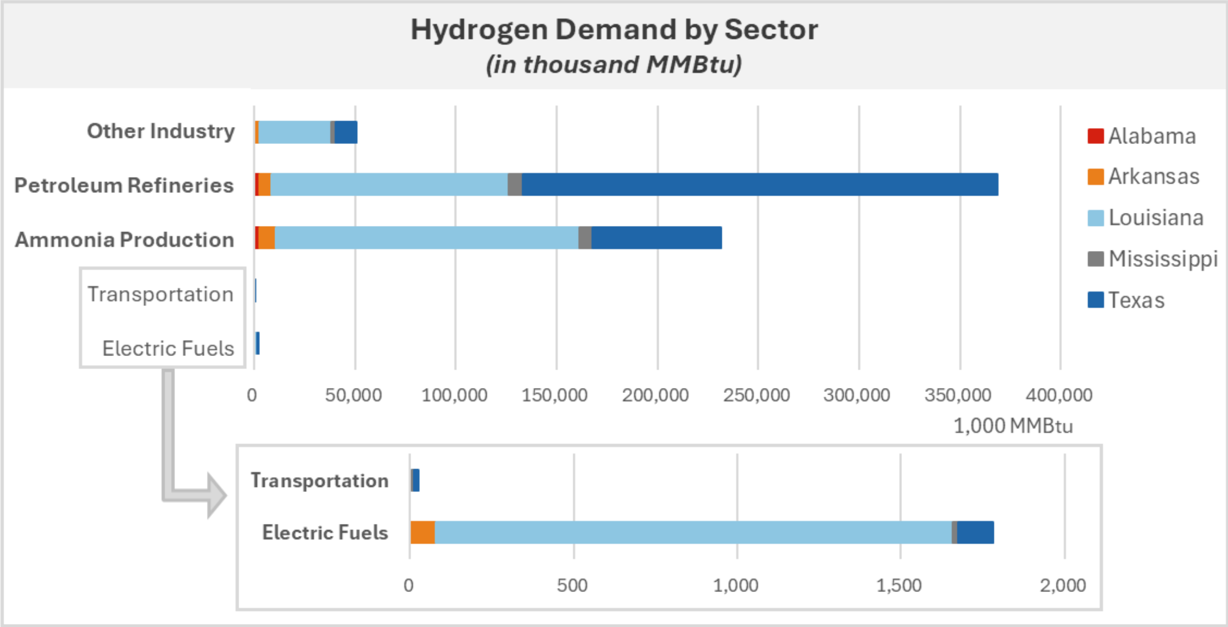


Figure 9. H_2 demand by sector and state. Note that power generation and iron & steel are zero in the Gulf Coast and that New Mexico was omitted due to no H_2 demand.

H_2 demand in the Gulf Coast region is currently dominated by the petroleum refining industry, particularly in Texas, where H_2 is essential for hydrocracking and desulfurization processes. Louisiana also contributes significantly, though its H_2 use is more closely tied to ammonia production. For additional discussion on current and projected H_2 demand across the petroleum, industrial and power, and transportation sectors in the region, see **Appendix F**.

Resource Availability in the Region

The Gulf Coast region has over 55 million tons of available biomass (primarily MSW) and over 1.3 trillion cubic feet of natural gas in addition to available LFG. The Gulf Coast is also particularly well-suited for CO_2 capture markets due to its extensive and mature industrial base. This section discusses the feedstock availability in each state and associated geographical trends.

Available Biomass Feedstock

The results of the Resource Availability Survey are summarized in **Figure 10**. The Gulf Coast possesses significant agricultural residues due to the wide distribution of available farmland, with higher concentrations found in Northeast Texas, Eastern Louisiana, and Eastern Arkansas (**Figure 11**). Forest residues are more abundant throughout the region, with the exception of Western and Central Texas and Southeastern Louisiana, which are characterized by prairies, desert, and swampland, respectively (**Figure 11**). MSW availability is moderate across the region, with higher volumes in more populated urban areas, particularly the Dallas-Fort Worth and Houston metropolitan areas (**Figure 12**).

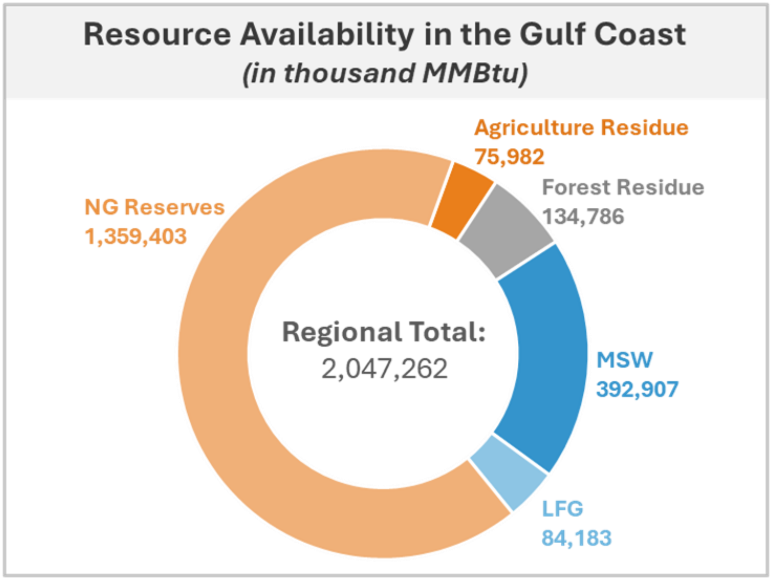


Figure 10. Resource availability in the Gulf Coast region in thousand MMBtu

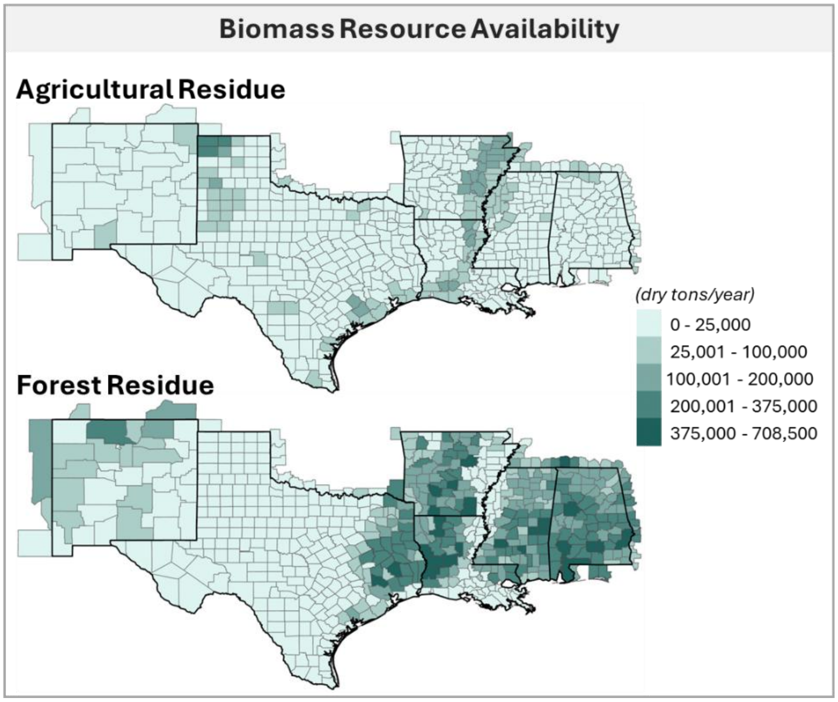


Figure 11. Gulf Coast agricultural and forest residue availability

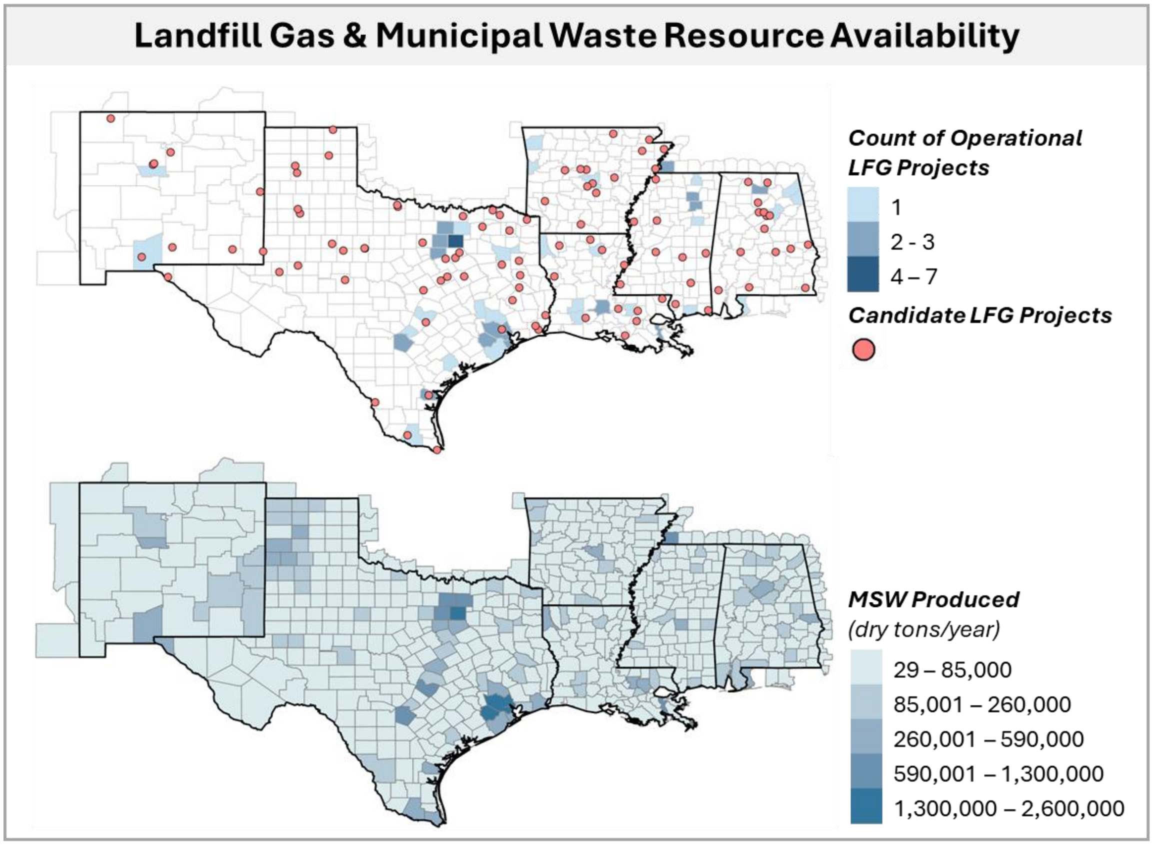


Figure 12. Gulf Coast LFG projects (active and candidates) by county and MSW production

These available biomass reserves make the Gulf Coast an especially viable exporter of emerging fuels like RNG, SNG, and H_2. The LFG data further supports this, with Texas having 367 million standard cubic feet per day (scf/d) of LFG produced across 161 locations, which accounts for approximately two-thirds of the overall landfill energy potential of the entire region. **Figure 12** shows the overall distribution of landfill sites with active energy projects and potential future projects throughout the region. Unlike other feedstocks considered, LFG potential is an evolving quantity as it depends on the microbial breakdown of waste (methanogenesis) in landfills. Thus, LFG potential must be regularly reassessed.

CO_2 Supply for SNG

The Gulf Coast demonstrates a wide range of industrial infrastructure, as visualized in **Figure 13**. The amount of available CO_2 that could be captured from various industrial plants in the Gulf Coast region is shown in **Figure 14**, with natural gas power plant data from the Energy Sector Risk Profile for the Gulf Coast (U.S. DOE Office of Electricity Delivery & Energy Reliability 2016) and industrial plant data from the NETL Industrial Capture report (Hughes et al. 2022). There are numerous power plants, natural gas processing facilities and chemical production plants in the Gulf Coast region. Two existing direct air capture hubs are located in Louisiana and Texas and several developed carbon storage sites are located in Northeastern New Mexico, Southeastern Texas, Central Louisiana, and Northern Alabama.

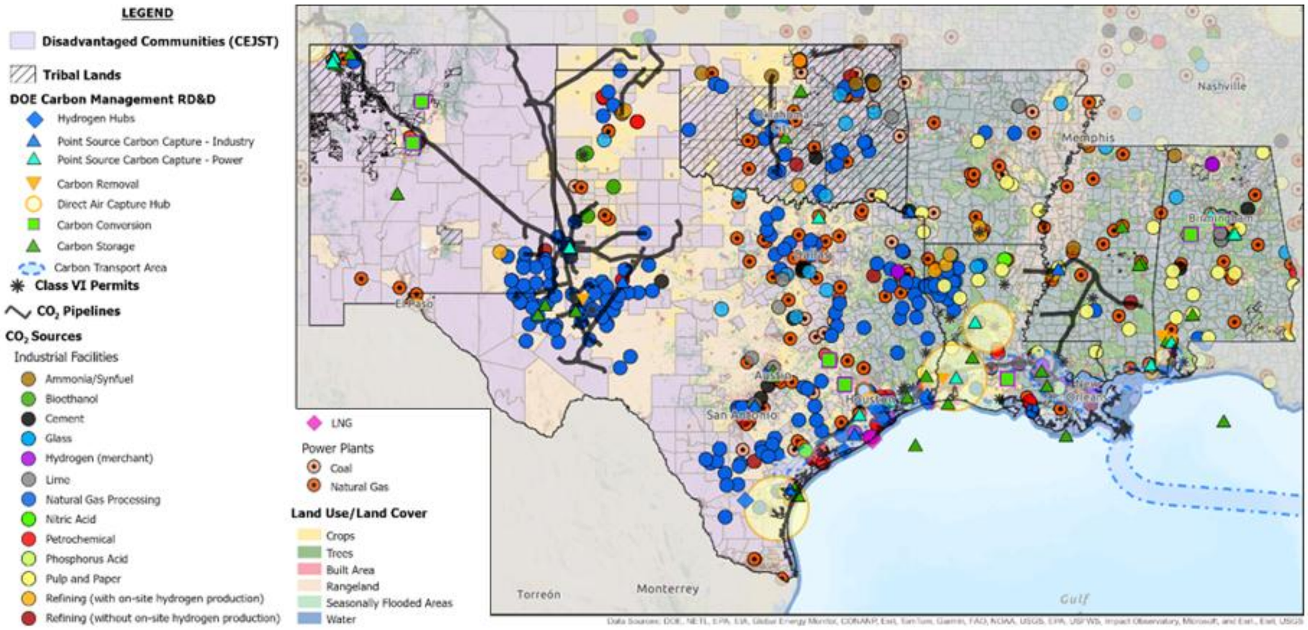


Figure 13. Industrial infrastructure in the Gulf Coast (U.S. DOE Fossil Energy and Carbon Management 2024)

Based on 2023 EPA GHGRP facility data, most reported CO_2 emissions from industrial natural gas end users in Texas and Louisiana are associated with power plants and chemical industries (**Figure 15**).

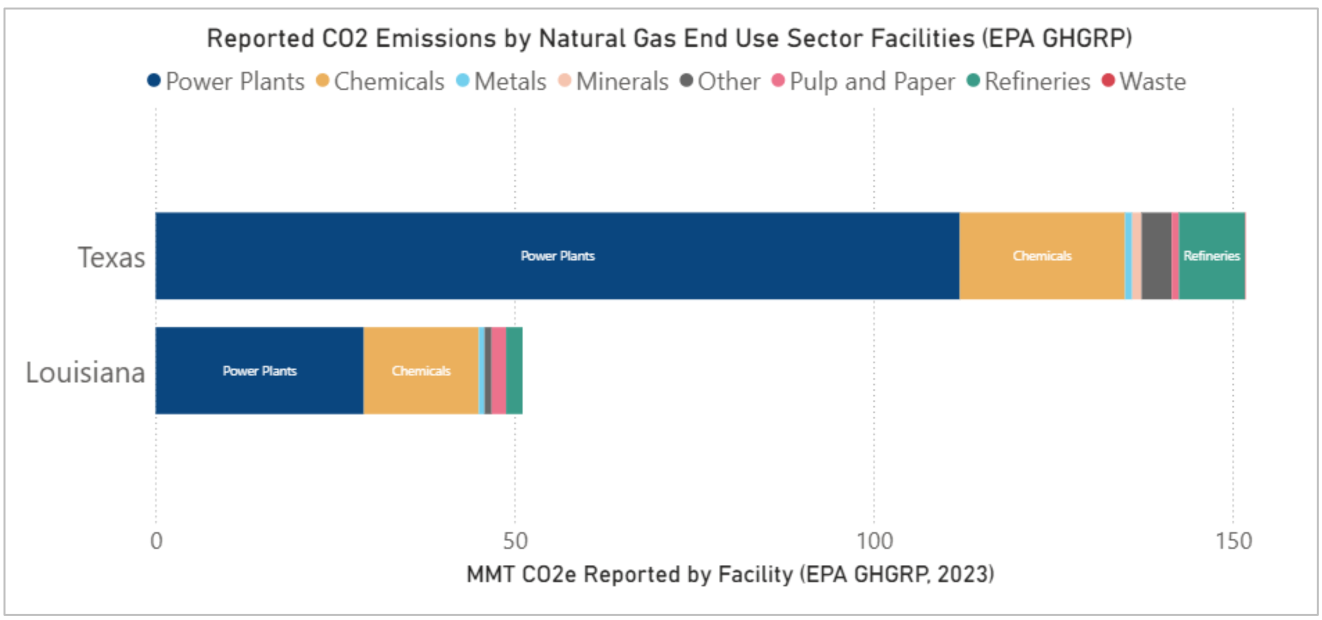


Figure 14. Reported CO_2 emissions by natural gas end use sector facilities (EPA GHGRP, 2024)

In addition to total emissions, it is important to consider the typical CO_2 concentrations expected from each industrial source. While natural gas processing plants are a richer

CO_2 source, power plants emit significantly more total CO_2 compared to natural gas processing plants. For example, in 2023, GHGRP-reporting power plants in Texas and Louisiana reported CO_2 emissions of approximately 18 MMT and 2.9 MMT, respectively. Moreover, some industries (e.g., chemicals manufacturing, cement plants, and iron/steel manufacturing plants) produce flue gas with higher CO_2 concentrations (Zuberi et al. 2024). These facilities that already emit higher-purity CO_2 can benefit from adopting CO_2 capture and purification technologies.

Figure 15 visualizes estimates of CO_2 availability from select point sources in each Gulf Coast state, which illustrates the state-level potential for SNG production in the region. Data was aggregated from the EPA Facility Level Information on Greenhouse Gases Tool (FLIGHT) (Environmental Protection Agency 2025).

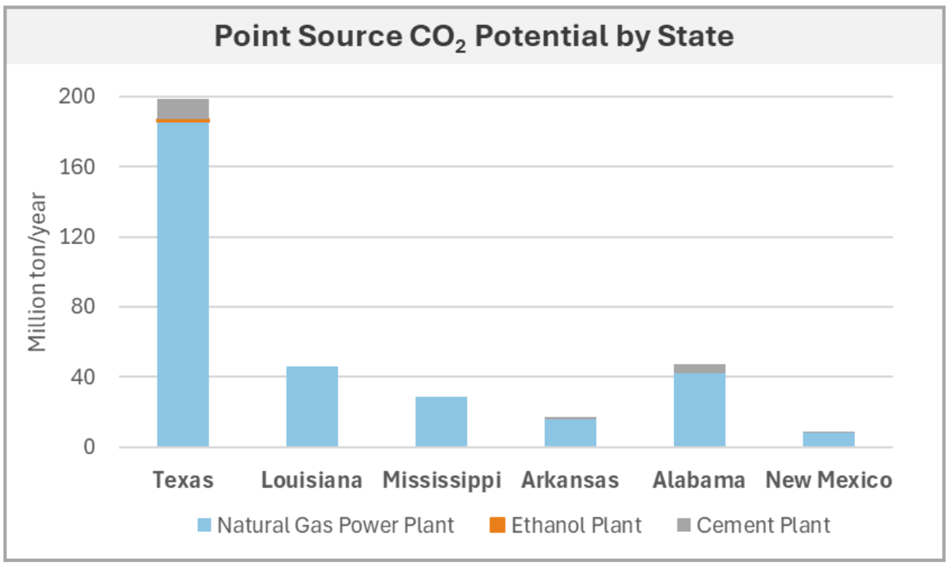


Figure 15. Point source CO_2 availability by state

Natural gas power plants represent the highest potential source of captured CO_2 in the Gulf Coast, with the ability to provide over 300 and 18 times more CO_2 than industrial ethanol and cement plants, respectively.

Renewable Electricity and Geothermal Potential

Figure 16 illustrates the distribution of renewable electricity and geothermal potential across the Gulf Coast region. The region has significant wind and solar potential, primarily in Texas and New Mexico. Of the various types of renewable power generation available, wind power is the most prominent, with the vast majority in Texas. In addition to wind and solar, Alabama and Arkansas add to the region’s renewable portfolio with some hydroelectric units. Geothermal energy is another promising resource, with Texas and New Mexico having the most favorable geological conditions. These two states have the greatest amount of Class 1 land, indicating high potential for commercial development. Overall, the Gulf Coast is well-positioned to leverage renewable resources to support production of emerging fuels, with wind and geothermal energy as the most promising for growth.

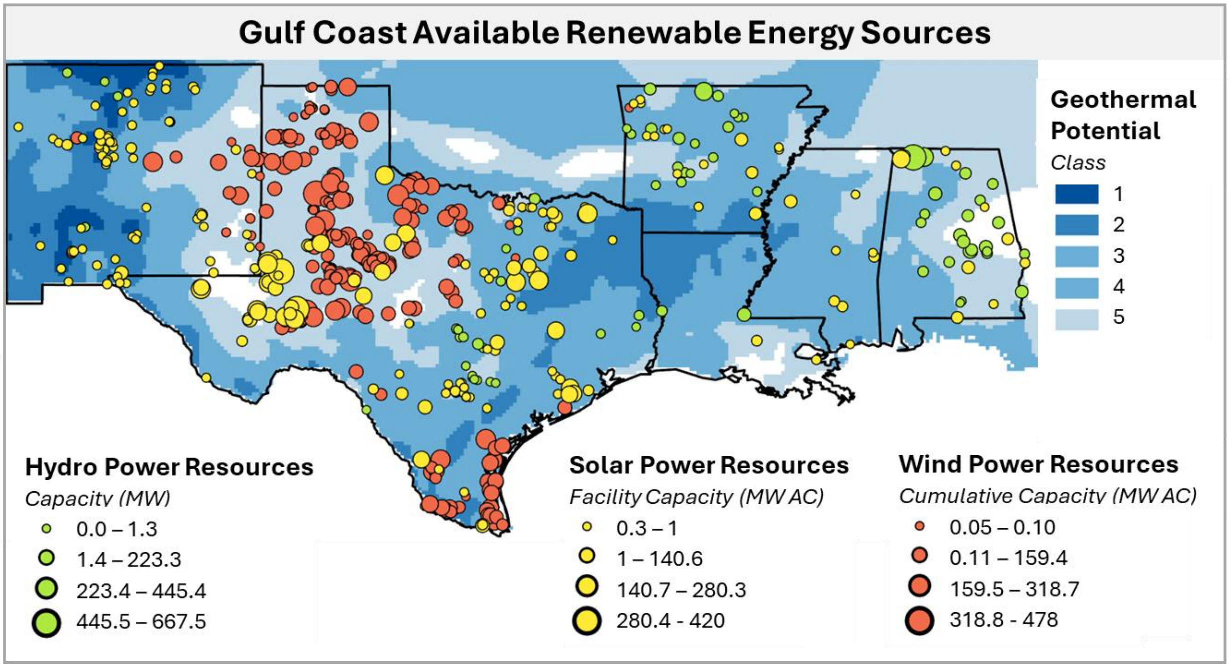


Figure 16. Gulf Coast available renewable energy sources

Producing and Delivering Emerging Fuels in Each State

Production Costs

State-level costs for producing low-carbon H_2, RNG, and SNG were developed and are further summarized in this section. The TEA used state-specific data for natural gas costs, electricity costs, labor costs, CO_2 T&S costs, point source CO_2 availability, and other resource availability. The individual levelized fuel costs for the six Gulf Coast states are summarized in **Figure 18** and **Figure 19**. Note that the boundary for the production costs is plant gate-to-gate, but delivery and interconnection costs are described in the **Delivery Costs** section.

Hydrogen Production Costs

The lowest-cost low-carbon H_2 production case is natural gas ATR w/ CCS (case H2-2) in Texas at \$1.40/kg H_2, while the most expensive low-carbon H_2 case is RNG SMR w/ CCS (case H2-5) in New Mexico at \$11.45/kg H_2. For all Gulf Coast states, the three lowest-cost H_2 production cases are, in order: natural gas ATR w/ CCS (case H2-2), NG SMR w/ CCS (case H2-1), and natural gas pyrolysis (case H2-7). For electrolytic H_2, the lowest cost is seen in Mississippi using electricity from a combined wind and solar system with storage (case H2-8a/b) at \$4.27/kg H_2. Overall, Texas shows the most favorable costs for natural gas-based H_2 due to its lower natural gas and CO_2 T&S costs, while Mississippi, New Mexico, and Texas show the most competitive costs for electrolytic H_2 due to their abundant wind and solar resources. Importantly, the levelized cost calculations account for coproduct sales, including the sale of carbon black for the plasma pyrolysis case (H2-7). **Figure 17** illustrates the regional and state-level levelized costs of the various H_2 pathways.

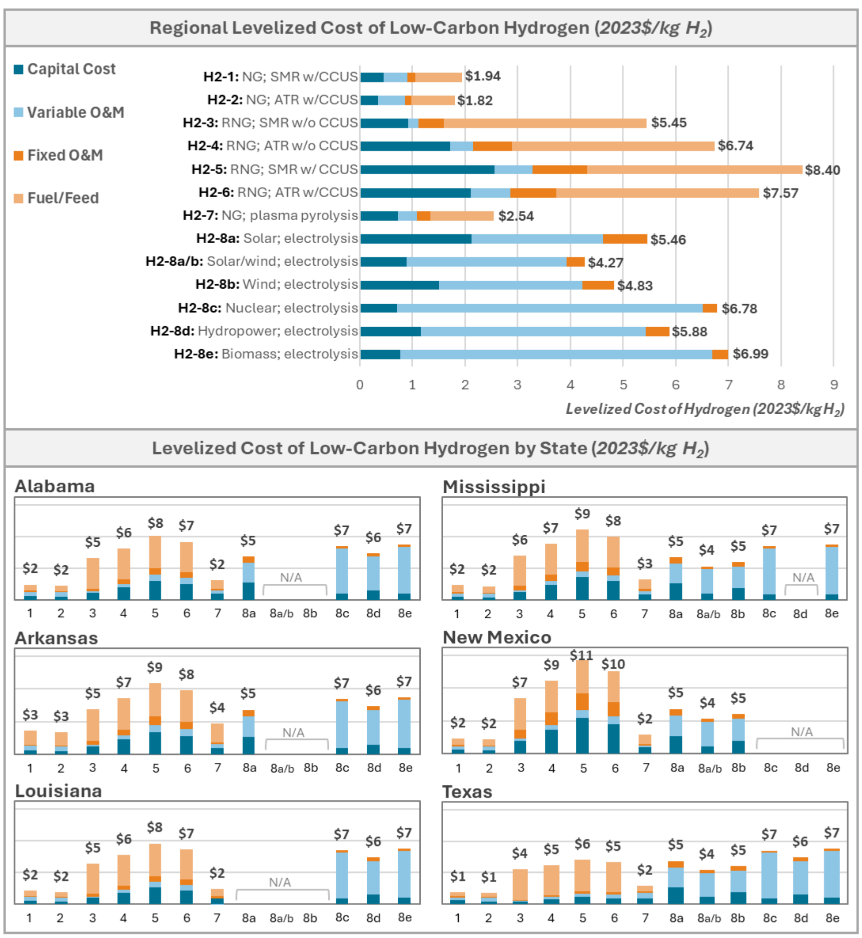


Figure 17. Gulf Coast state level H_2 production costs (2023 \$USD/ kg H_2)

RNG and SNG Production Costs

Among the RNG and SNG pathways considered, the most cost-competitive option is LFG to RNG (RNG-4) in Texas at $32.8/MMBtu due to the state's abundant LFG resources. In contrast, the most expensive option is woody biomass gasification to RNG (RNG-2) in New Mexico at $189/MMBtu due to the lack of forest residues in the state. The lowest-cost SNG can be produced in Mississippi, New Mexico, and Texas due to the relatively lower costs of electrolytic H_2 that can be sourced from these states. For most states, LFG to RNG (RNG-4) is the lowest-cost option. The exception is New Mexico, where CO_2 sourced from a power plant combined with electrolytic H_2 through a combined wind and solar system is the most economic option (SNG-1a/b). Importantly, the levelized cost calculations account for coproduct sales, including electricity exported to the grid in the gasification to RNG cases (RNG-1 to RNG-3). **Figure 18** illustrates the regional and state-level levelized costs of the various RNG and SNG pathways.

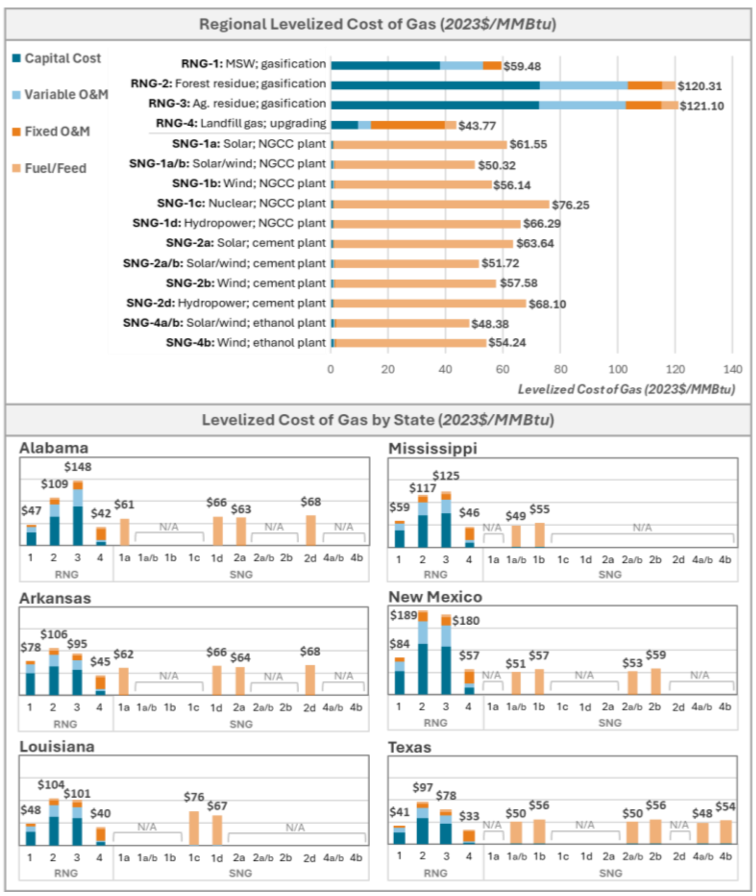


Figure 18. Gulf Coast state level RNG and SNG production costs (2023 $USD/MMBtu)

Fuel Pathway Production Emissions

To conceptualize the upper and lower bounds of expected emissions for RNG pathways, the two RNG scenarios have been defined differently as compared to the TEA results. Specifically, the RNG pathways for LCA are defined as follows: RNG-1A is defined as representing woody biomass gasification (through thermal), and RNG-1B is defined as sourced from MSW through anaerobic digestion. Likewise, an additional case H2-8 (H_2 production with low-carbon electricity) is assumed to be a single pathway that has a mix of low-carbon sources not including nuclear, as detailed in **Figure 19**.

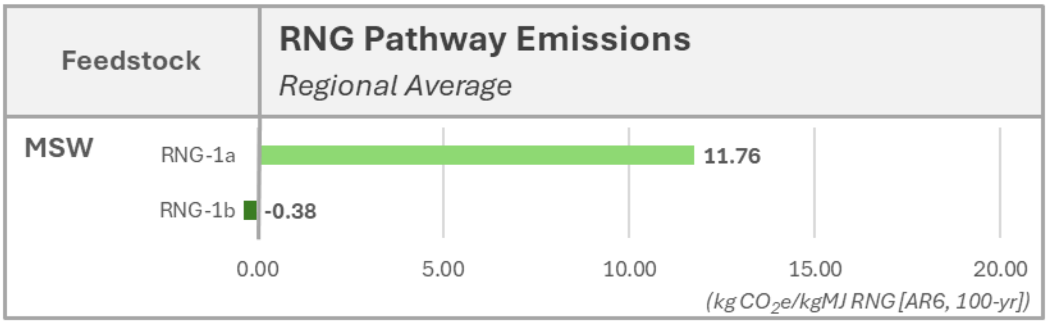


Figure 19. RNG production pathway emissions

Parallel low-carbon electrolysis scenarios are shown in **Figure 20** as case H2-8a through H2-8e andH2-8(a/b), which represents a mix of solar and wind energy. In general, the GHG intensity of the low-carbon electricity pathways in different states do not differ significantly (i.e., approximately 5%) due to the upstream electricity component of the life cycle being the singular impact by each technology change, and the GHG intensities of renewable generation within the Gulf Coast states do not change appreciably. However, an exception is the GHG intensity associated with biomass-generated electricity (H2-8e) as it does vary appreciably (i.e., approximately 30%) between states given differences in agricultural feedstocks used. Overall, emissions from electrolysis-based H_2 production using renewable energy are comparable to those from fossil-based pathways that incorporate CCS.

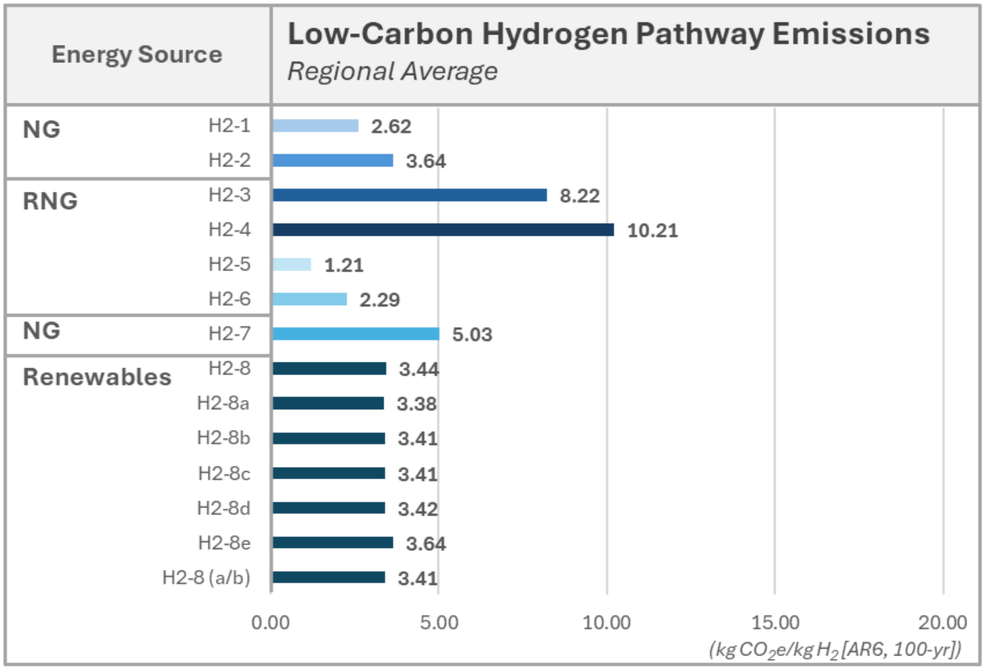


Figure 20. Low-carbon H_2 production pathway emissions

LCA results of the SNG cases range from 12.91–19.75 kg CO_2/ MMBtu [AR6,100-yr] SNG produced (**Figure 21**), which demonstrates a less significant impact of emissions attributable to the different CO_2 and renewable electricity sources considered. However, the lowest CO_2 emissions are associated with the SNG-2d case: electrolytic H_2 produced using hydropower combined with CO_2 captured from a cement plant point source. The highest CO_2 emissions are associated with the SNG-3 case: electrolytic H_2 combined with CO_2 captured from steel plant point source.

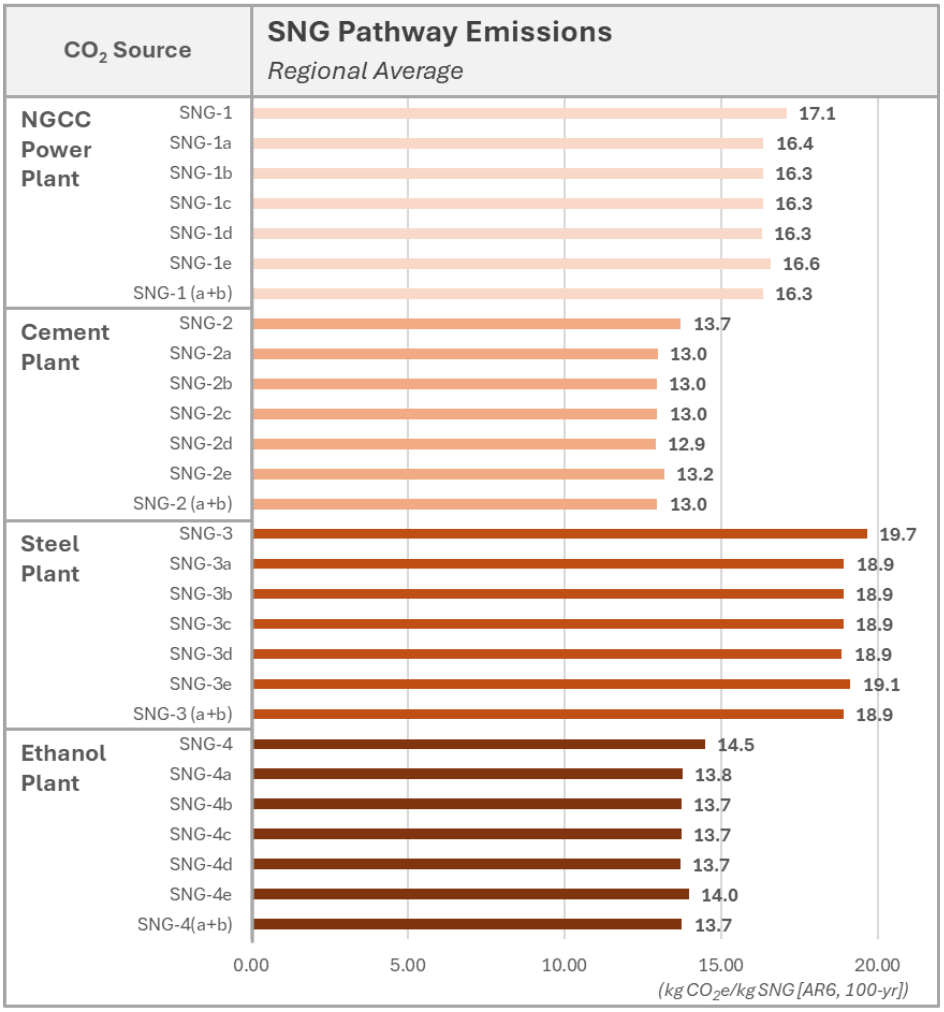


Figure 21. SNG production pathway emissions

The SNG cases that utilize biomass electricity ("d" cases) are associated with moderately increased life cycle (LC) scores compared to the solar, wind, nuclear, and hydropower cases. In the cases of mixed renewable electricity utilized, the LC scores are assumed to be similar to both standalone solar and wind-powered SNG cases. State-level differences in calculated kg CO_2e/ MMBtu SNG are also found to be insignificant for each of the SNG cases. However, the regional kg CO_2e/kg SNG can vary depending on the actual distances between feedstocks, production facilities, and end users.

The SNG results shown are derived through a hybrid methodology combining detailed life cycle modeling in openLCA and adjustments for electricity source variation. Additional explanation of LCA assumptions is further discussed in **Appendix D**.

Delivery Costs

The Hydrogen Delivery Scenario Analysis Model (HDSAM), developed by Argonne National Laboratory, was used to estimate H_2 transportation and delivery costs (Elgowainy et al. 2024a). Region-specific factors such as electricity prices, natural gas prices, and labor costs were incorporated into HDSAM to provide estimates more specific to the Gulf Coast region, reported in 2023 costs (see **Appendix G** for additional assumptions). Model results indicate that gaseous H_2 delivery is expected to cost less than 50% per kilogram transported compared to liquid H_2 delivery, across a range of facility scales (**Figure 22**).

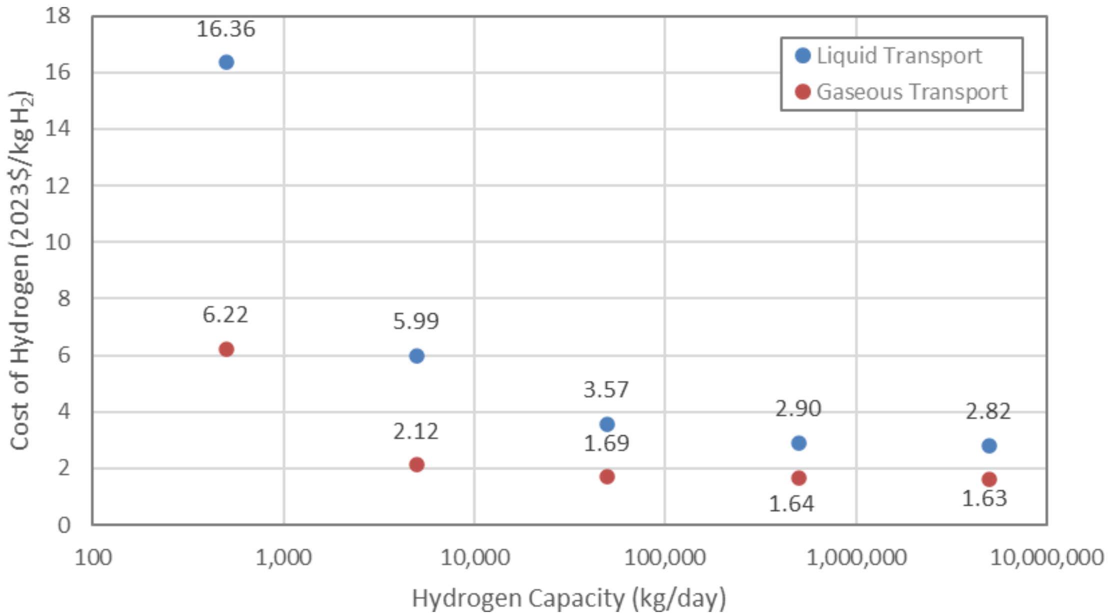


Figure 22. Graphical representation of H_2 delivery costs

As for SNG and RNG projects, they may have additional pipeline interconnection costs, depending on the location of the production plant, existing infrastructure availability, and scale of the project (Lowell & Jones, 2019). For the SNG cases (SNG-1 through SNG-4), the plant can be co-located near the CO_2 point source, which would reduce CO_2 transportation costs and could leverage existing pipeline infrastructure near the point source plant. For the MSW to RNG case (RNG-1), pipeline interconnection costs may be lower than other RNG sources due to the proximity of many landfills to existing pipelines. An M.J. Bradley & Associates report states that interconnection costs are a function of project size and can range from $39/MMBtu (in 2023$) for small projects (10 MMBtu/hr) to $13/MMBtu (in 2023$) for medium-sized projects (100 MMBtu/hr) (Dana Lowell and Brian Jones 2019).

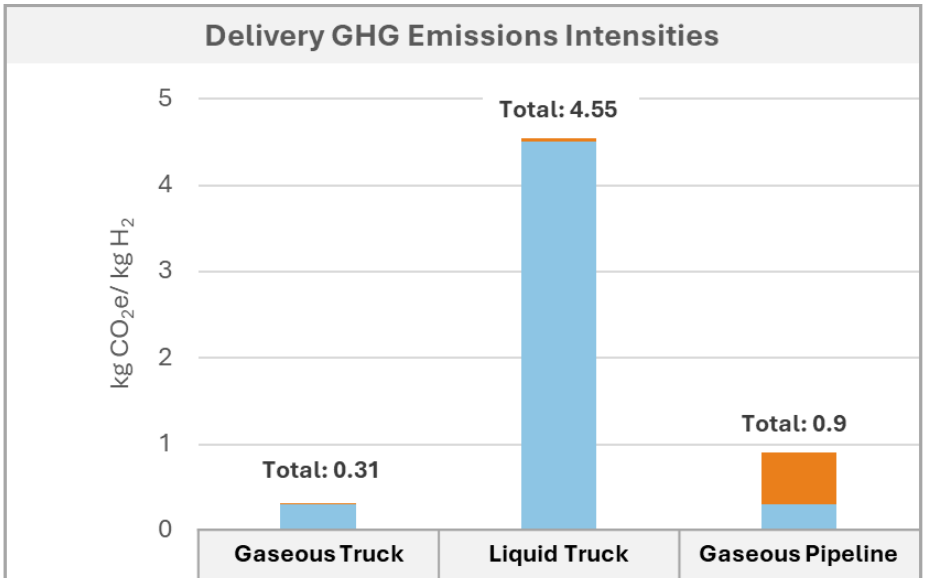
For the biomass to RNG cases (RNG-2 and RNG-3), the gasification facility may be in proximity to biomass plants to reduce biomass transportation costs but may not be near existing pipeline infrastructure, resulting in higher costs for pipeline interconnection. The M.J. Bradley & Associates report stated that costs for dairy RNG, which are typically located in remote locations similar to biomass plants, range from $10/MMBtu for larger projects to $30/MMBtu for smaller projects, due to pipeline extensions required to connect existing natural gas networks (Dana Lowell and Brian Jones 2019). Adjusting these values to 2023$ and factoring in the capacity of the RNG-2 and RNG-3 cases specific to the Gulf Coast results in estimated interconnection costs of $24/MMBtu for RNG-2 and $17/MMBtu for RNG-3.

Delivery Emissions

The emissions from preparing and delivering H_2 to market were estimated, excluding embodied emissions from manufacturing delivery equipment, but including operational emissions. The TEA indicates that the electricity needed to compress and liquefy H_2 is 0.562 kWh/kg and 9 kWh/kg, respectively. At the Gulf Coast region level, the GHG emissions of upstream electricity to support those processes are 0.3 and 4.5 kg CO_2e/kg, respectively (using a basis of 500 kg CO_2e/MWh) (**Figure 23**).

Assuming a 120 km round-trip delivery distance by truck, a liquid delivery truck would carry a product mass of 3,500 kg (3.5 tonnes) and a gaseous truck 600 kg (0.6 tonnes). Given an average GHG intensity of 1.28×10^{-4} kg CO_2e per ton-km for U.S. diesel trucks, total delivery emissions are estimated at 0.05 kg CO_2e for liquid H_2 and 0.01 kg CO_2e for gaseous H_2 based on 420 and 72 ton-km delivery routes, respectively. These conservative estimates exclude the reduced load on return trips and the emissions from manufacturing pressure vessels, given the already minimal values.

For H_2 delivery via pipeline, this study uses an emissions factor of 0.6 kg CO_2e per kg H_2, based on North American data for 1,000-km (621 mi) pipelines (Di Lullo et al. 2022). The modeled steel alloy pipeline is 200 km (124 mi) long, with a 12-inch diameter, a 30-year lifespan, and a peak flow rate of 276,495 kg/day operating at 800-900 psig (Lewis et al. 2022). The pipeline's emissions include both embodied construction impacts and fugitive emissions. These were retained in this analysis to support comparisons between different pipeline types in the following section.



	Gaseous Truck	Liquid Truck	Gaseous Pipeline
Delivery	0.01	0.05	0.6
Compressor/ Liquefaction	0.3	4.5	0.3

Figure 23. Summary of delivery GHG intensities in the Gulf Coast Region in kg CO_2e/ kg H_2

A similar H_2 delivery LCA conducted by Argonne National Laboratory examined regional delivery emissions across the U.S., including the Gulf Coast region, which aligns with the Southeastern Electric Reliability Corporation (SERC) boundaries. For a delivery scenario involving a 100-km transmission pipeline and 50-km distribution via tube trailer, total well-to-wheel emissions were estimated at 12 kg CO_2e/kg H_2, with delivery contributing approximately 2.3 kg CO_2e/kg H_2 (including pipeline, terminal, trucking, and refueling station emissions). The study identified a GHG emissions crossover point between gaseous and liquid H_2 trucking in the Texas Reliability Entity (TRE) and SERC regions at approximately 2,900 km (1,802 miles) for well-to-wheel emissions using SMR production, beyond which both delivery modes result in equivalent emissions (Frank et al. 2021).

For liquid H_2 delivery, the largest contributor to the GHG intensity is the on-site liquefier with estimated emissions of 5.4 kg CO_2e/kg H_2, which is comparable to the production emissions. While estimated independently, these values are similar to those published in a 2024 Argonne National Laboratory study that estimated 5 kg CO_2e/kg H_2 (Elgowainy et al. 2024a). In comparison, tother components (i.e., compressor, truck delivery) are relatively small contributors to GHG intensity. Compression contributes approximately 0.3 to 0.8 kg CO_2e/kg H_2, with lower values typically associated with pipeline delivery and higher values with tube trailers. At refueling stations, additional pressurization for pipeline-delivered H_2 adds about 1.2 kg CO_2e/kg H_2 (Elgowainy et al. 2024a).

Assuming the electricity used for H_2 compression and delivery comes from the standard grid mix and considering the full scope of delivery emissions (including compression, liquefaction, transportation, and/or any further compression or precooling needed for dispensing or storage), the total emissions estimated in the Argonne study range from 1.24 to 1.55 kg CO_2e/kg H_2 for gaseous H_2 via pipeline, 0.86 to 1.70 kg CO_2e/kg H_2 for tube trailers, and 0.21 to 5.21 kg CO_2e/kg H_2 for liquid H_2 (Elgowainy et al. 2024a).

End-Use Costs and Emissions of H_2 Blends

True economic and environmental assessments of H_2 blends require comparisons on a head-to-head basis against other uses of natural gas. End uses of H_2 blends could be associated with electricity generation, mobility, or other industrial/commercial/residential applications. This section compares costs and emission impacts associated with the considered fuel pathways in specific end-use applications. In some cases, substituting the fuels produced above have no tradeoffs or other concerns, while in others, there are compatibility and efficiency issues to be considered. Since no end-use retrofitting or replacement would be needed for the use of RNG or SNG in place of natural gas, the following sections focus on costs for end-use utilization of H_2.

Power Generation Costs

H_2 can be fired in gas turbines to generate electricity without any direct CO_2 emissions. Electricity prices are estimated with an assumed energy content of 33.3 kWh/kg for H_2 (The Engineering ToolBox 2003) and efficiency of 40.3% for a L30A turbine combusting H_2 (Kawasaki 2025). These assumptions result in electricity price estimates of $135.6/MWh for the lowest-cost H_2 scenario in the Gulf Coast (H2-2) and $521/MWh for the highest cost H_2 scenario in the Gulf Coast (H2-8e). Note that these estimates only account for the cost of the H_2 feedstock. Furthermore, H_2-ready turbines typically cost more than conventional natural gas turbines due to design adaptations needed for H_2's high diffusivity, low ignition energy, and different combustion dynamics (NETL 2022).

As a comparison, the levelized cost of energy (LCOE), adjusted to 2023$, for a natural gas combined cycle (NGCC) power plant without carbon capture is $51.6/MWh and $82.3/MWh for an NGCC power plant with 95 percent capture (Schmitt, Tommy et al. 2022).

Transportation Costs

H_2 can be used for fuel cell or H_2 internal combustion engines (H_2-ICEs) vehicles. Fuel cell vehicles require ultra-high-purity H_2 (i.e., 99.97%) with strict specifications defined by the ISO 14687:2025 standard (ISO 2025), to ensure that impurities do not damage the fuel cell stack or reduce its efficiency. Additional purification to the ISO standard may increase H_2 production costs by 18–25% (PW Consulting Automotive & Machinery Research Center 2025). Two classes of fuel cell vehicles are studied: medium-heavy-duty vehicles (e.g., trucks, buses, and vans) and light-duty vehicles (e.g., passenger cars, pickup trucks, and small vans). The estimated regional H_2 market demand for medium-heavy duty vehicles and light-duty vehicles is 50,000 kg/day and 600 kg/day, respectively (Elgowainy et al. 2024b). The light-duty scenario is based on servicing the largest city in the region, Houston, Texas, which has a population of 2.314 million people, which improves economies of scale for the terminal costs. **Table 3** summarizes the calculated costs of H_2 end use in both light- and medium-duty vehicles at liquid-based and gas-based refueling stations. The boundaries of these costs include the liquid- or gas-based refueling station and any on-site storage needed. The costs reported include both capital and operating costs and have been normalized by H_2 flow rate. H_2 production and delivery costs can be added to the refueling station costs to estimate total costs for end-use in transportation.

Table 3. Cost of H_2 for vehicle fueling station end-use

Refueling Station Costs (2023$/kg H_2)	Liquid-Based Refueling Station		Gas-Based Refueling Station	
	Medium-Heavy Duty Vehicle	Light-Duty Vehicle	Medium-Heavy Duty Vehicle	Light-Duty Vehicle
Storage	0.89	0.93	0.24	0.23
Refueling Station	1.70	2.97	2.52	2.63
TOTAL	2.59	3.90	2.76	2.86

Alternatively, H_2-ICEs can offer a cost advantage over fuel cell vehicles due to their more lenient H_2 purity requirements (i.e., 96%). H_2-ICEs can operate effectively with lower purity levels, reducing the need for costly purification, making them an attractive option for decarbonizing transportation where fuel purity logistics and cost are limiting factors.

Other advantages of H_2-ICEs include power-density improvement, reduced thermal losses, and improved thermal efficiency (Stepien, 2021). However, challenges to consider for H_2-ICEs include high combustion temperatures, NOx emissions, H_2 embrittlement of engine components, and pre-ignition (Stepien, Z 2021).

Industrial Costs

Industrial end-uses for H_2 include petroleum refining, such as hydrocracking and desulfurization, ammonia production for fertilizer, methanol production, and steel manufacturing. Per a DOE study, the price of ammonia is estimated at $569/tonne when H_2 costs $4.53/kg[1] (George Thomas, George Parks 2006). Based on this assumption, it is estimated that ammonia production in the Gulf Cost could cost $176/tonne for the lowest-cost H_2 scenario (case H2-2), and $879/tonne for the highest cost H_2 scenario (case H2-8e). For comparison, the average market price of fossil-based ammonia in 2023 was $480/tonne (U.S. Department of the Interior and U.S. Geological Survey 2025).

An Argonne National Laboratory study estimates that methanol costs $1,420-1,460/kg when H_2 costs $5.72/kg[2] (Zang et al. 2021). Based on this assumption, estimated Gulf Coast methanol prices are $348-357/tonne for the lowest cost H_2 scenario (case H2-2) and $1,738-1,786/tonne for the highest cost H_2 scenario (case H2-8e). For comparison, 2023 costs for fossil-based methanol were estimated at $110– 275/tonne (Joint Center Deployment & Research in Earth Abundant Materials 2023).

Power Generation Emissions

From DOE's natural gas baseline study, producing electricity from an NGCC F-class plant results in life cycle GHG emissions of 467 kg CO_2e/kWh, of which 61 kg CO_2e/kWh come from upstream natural gas emissions (Khutal, et al., 2024). Similarly, an F-class NGCC plant with 90% carbon capture is estimated to have emissions of 160 kg CO_2e/kWh, with 91 kg CO_2e/kWh attributed to upstream emissions. This higher upstream intensity is due to additional energy required for the capture technology and CO_2 compression. H_2-based alternatives for power production are excluded from this section.

As in the cost section, this subsection assumes that substituting natural gas with SNG or RNG requires no additional on-site activities (i.e., they are one-to-one fuel

[1] Converted 2006 costs to 2023 costs using the U.S. Bureau of Labor Statistics' Consumer Price Index Inflation Calculator.

[2] Converted 2021 costs to 2023 costs using the U.S. Bureau of Labor Statistics' Consumer Price Index Inflation Calculator.

replacements). Therefore, the only difference in emissions between RNG/SNG and fossil natural gas are their upstream life cycle emissions. Based on the Gulf Coast regional emissions data presented above, **Figure 24** The results show that the RNG and natural gas with CCS pathways could yield significant emissions reduction. Compared to natural gas without CCS, using RNG with CCS and natural gas with CCS could reduce carbon emissions by approximately 96% and 65%, respectively. summarizes expected emissions associated with natural gas used for power generation (the RNG case assumes RNG-1b3). The results show that the RNG and natural gas with CCS pathways could yield significant emissions reduction. Compared to natural gas without CCS, using RNG with CCS and natural gas with CCS could reduce carbon emissions by approximately 96% and 65%, respectively.

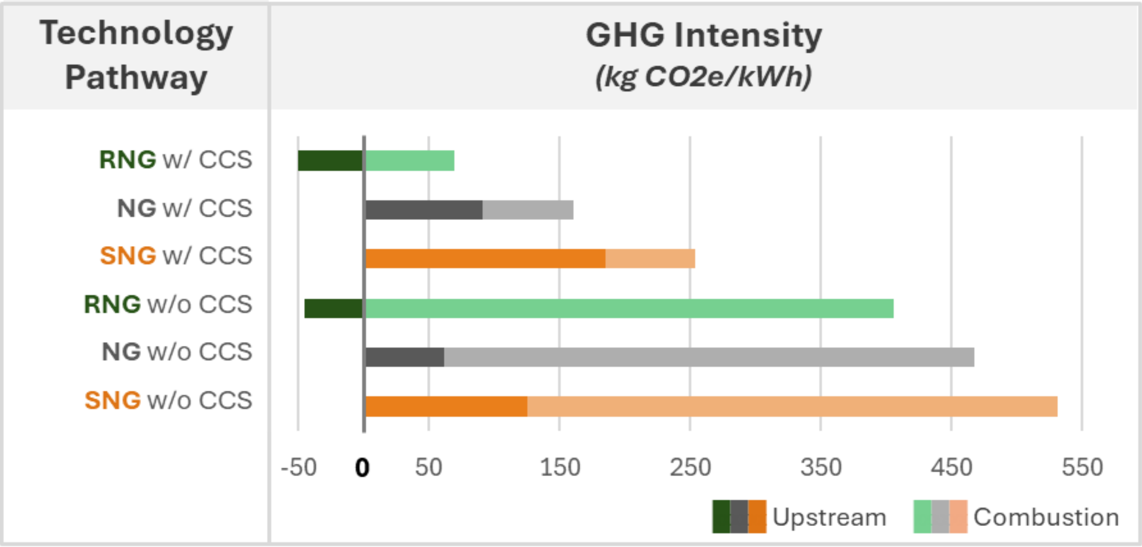


Figure 24. Expected emissions for natural gas power generation in the Gulf Coast

Transportation Emissions

Fuel transportation (from fuel production location to fuel use location) of H_2 is considered versus natural gas. The GREET model already establishes numerous well to wheel emissions estimates for various vehicle fuel transportation pathways, as summarized in **Figure 25**. Note that these values are for highway trucks but align well with other vehicle sizes. Electrolytic H_2 pathways exhibit the lowest GHG intensities among the options considered. Across all technology pathways, pipeline delivery results

[3] These estimates are based on feed rates of 128 kg/MWh for NGCC and 145 kg/MWh for NGCC with 90% CCS, assuming a gas energy density of 54 MJ/kg.

in the lowest emissions as larger volumes of H_2 can be transported over long distances. These results highlight the environmental benefit of pipeline delivery.

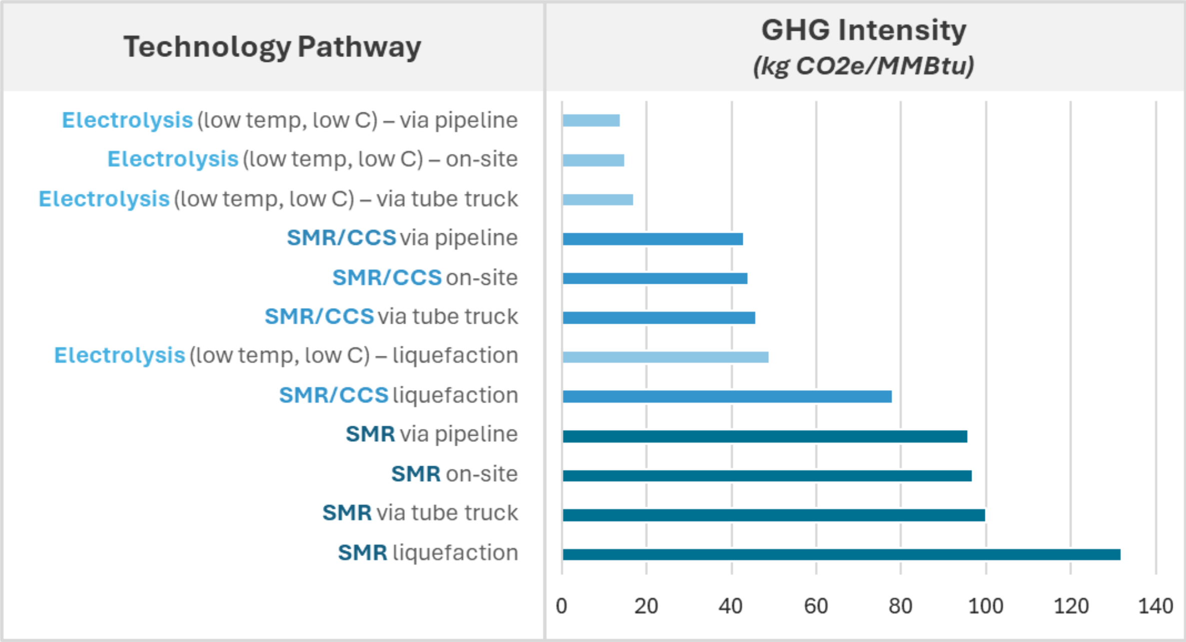


Figure 25. GHG intensity for various technology pathways related to transportation

Industrial Emissions

The body of research on decarbonizing heavy industry with H_2 is still expanding. A recent review summarizes emissions estimates for various U.S. industries (Zhu et al. 2025). Most H_2 applications focus on high-thermal load processes where H_2 can replace other existing fuels (e.g., coal, coke, natural gas), especially in sectors with limited decarbonization options. For example, benefits of blending H_2 in blast furnaces may reduce carbon emissions by 20% (Yilmaz et al. 2017). In contrast, using H_2 in iron-making (e.g., sponge iron through direct iron reduction) can cut GHG emissions by up to 90% when low-carbon H_2 is used (Comfort Ramakgala and Gwiranai Danha 2019). For crude oil refining and chemical production, a 25% reduction is found. Similarly, a 12% reduction is found for methanol production. Meeting local H_2 demand would likely require on-site electrolyzers, which would need renewable electricity to achieve emissions targets. Given the scale of iron and steel facilities, the electricity required could be significant.

Beyond high thermal load processes, a major near-term opportunity for industrial H_2 use is ammonia production. Conventional ammonia production involves reacting natural gas with steam to produce H_2, which is then reacted with nitrogen from air. This process is one of the largest GHG emissions sources in the chemicals industry. Ammonia itself is a versatile feedstock, primarily used in fertilizers, but also potentially as fuel for vehicles or power generation. However, with a reliable and low-carbon H_2 source, the conventional step could be bypassed, allowing direct combination with nitrogen and can result in up to 30% emissions reductions.

Potential Emissions Reduction Scenarios Utilizing Emerging Fuel Blends

Low-Carbon H_2

The Low Carbon H_2 case has the same assumptions as the BAU AEO23 Reference case in all aspects except the following:

- H_2 is assumed to be blended into natural gas pipelines at rates of 5 vol% and 20 vol%. Thus, two separate cases are run to represent these rates.
- All new H_2 is assumed to be produced using low-carbon H_2, i.e., natural gas SMR without CCS is not used.

The cost and performance data for LowC H_2 is based on the TEA Methodology. The final price of natural gas to the end use sectors is also impacted by the presence of blended H_2.

RNG

The RNG case has the same assumptions as the BAU AEO23 Reference case in all aspects except the following:

- RNG is assumed to be blended into natural gas pipelines at rates of 5 vol% and 20 vol%. Thus, two separate cases are run to represent these rates.
- All new RNG is assumed to be produced using MSW gasification H_2 production (using the RNG SMR/ATR process) and for blending into natural gas pipelines.
- The delivered RNG price is based on the marginal price calculated in the model plus a delivery adder. The final price is a function of the H_2 price.
- RNG is assumed to be a zero-emissions fuel and emissions from blended NG delivered are, therefore, lower based on the amount of blended.

The cost and performance data for RNG is based on the TEA methodology. The final price of natural gas to the end use sectors is also impacted by the presence of blended RNG.

SNG

The SNG case has the same assumptions as the BAU AEO23 Reference case in all aspects except the following:

- SNG is assumed to be blended into natural gas pipelines at rates of 5 vol% and 20 vol%. Thus, two separate cases are run to represent these rates.
- All new SNG is assumed to be produced using H_2 from electrolysis processes, i.e., SMR and ATR technologies are not used.
- Total SNG demand in the model is equal to the SNG demanded for blending into natural gas pipelines.
- The delivered SNG price is based on the marginal price calculated in the model plus a delivery adder. The final price is a function of the H_2 price, CO_2 price from capture, and CO_2 transport costs.
- SNG is assumed to be a zero-emissions fuel and emissions from blended natural gas delivered are, therefore, lower based on the amount of blended.
- The emissions from each sector are also updated based on the CO_2 captured to produce SNG, lowering the emissions further.

The cost and performance data for SNG is based on the TEA methodology. The final price of natural gas to the end use sectors is also impacted by the presence of blended SNG.

Blend Scenario Results Summary

The NEMS scenario results can be found in **Appendix H**. **Figure 26** visualizes the LowC H_2, RNG, SNG blend cases with natural gas consumption projections to 2050.

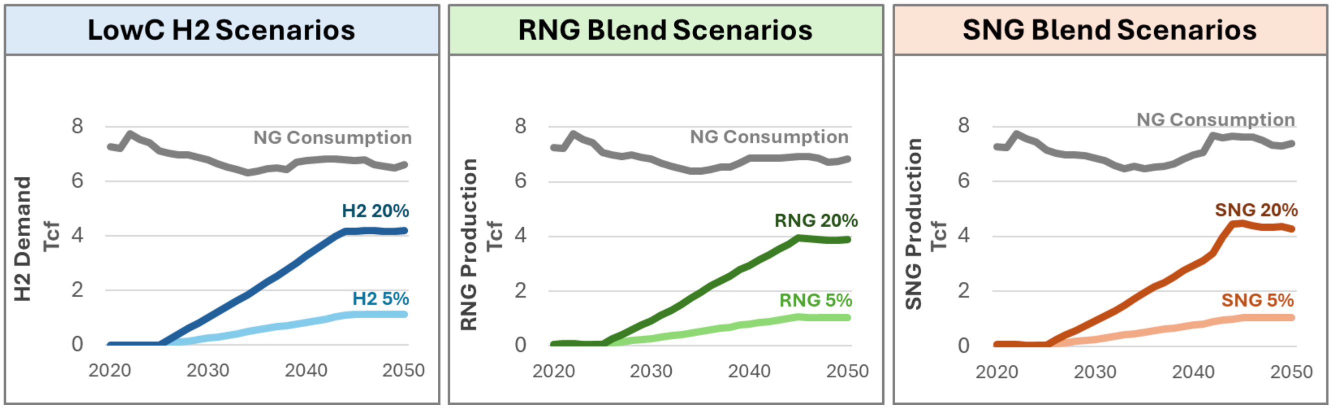


Figure 26. Summary of Gulf Coast blend scenario analyses

In the SNG blending cases, particularly the SNG 20 vol% case, power generation and capacity are projected to grow significantly by 2035, primarily in renewables. This growth is comparable to most of the alternative scenarios except for AEO23 and Low OGS. By 2035, coal power is nearly eliminated, and natural gas demand in the power sector is reduced, leading to temporary lower natural gas prices. H_2 demand surges due to its necessity for SNG production via electrolysis. Power sales to H_2 increase sharply, and total power sales are highest in this scenario in 2035. SNG production scales with blending levels, and in the 20% case, additional SNG is needed to meet increased natural gas demand. However, the price of SNG rises rapidly due to expensive electrolysis-based H_2 production, CO_2 capture, and transportation costs, reaching >$100/MMBtu (2023$) by 2035.

The low-carbon H_2 cases show high H_2 demand due to blending requirements, with production primarily from SMR/ATR with CCS. This shift reduces natural gas use in the industrial sector as H_2 displaces it. H_2 demand is significant, but prices remain lower, <$50/MMBtu (2023$) in 2035, than in the SNG 20 vol% case since production does not rely solely on electrolysis.

In the RNG blending cases, RNG production scales with blending levels, but it remains costly compared to other H_2 production methods. H_2 is not produced from RNG in any cases as RNG prices remain higher than other competing H_2 production technologies.

It is important to note that the natural gas consumption estimates presented here do not include the additional gas volumes needed to maintain energy delivery when H_2 is blended into the gas supply. Because H_2 has about one-third the energy content of natural gas, the overall volume of gas delivered will need to increase to deliver the same amount of energy. Assuming typical natural gas has a HHV of 1,030 Btu/scf, a 5 vol% H_2 blend and 20 vol% H_2 blend would have a HHV of 994.75 Btu/scf and 889 Btu/scf, respectively. In 2023, the estimated Gulf Coast natural gas consumption was 3,626,170 cubic feet. To meet this demand with a 5 vol% H_2 blend, approximately 3,754,667 cubic feet would be required. With a 20% vol% blend, the volume increases to approximately 4,201,299 cubic feet. This is an important consideration for operators considering introducing H_2 into their systems, as the throughput will need to increase to continue meeting the same end-use demand.

Reconciling Available Feedstocks for RNG and SNG Production

While the Gulf Coast possesses abundant feedstock resources, the resource availability assessment indicated there is insufficient readily available feedstock in the region to produce the necessary volume of RNG to achieve a 20 vol% blending target. **Figure 27** visualizes the reconciliation of available regional feedstock with the NEMS model blending assumptions.

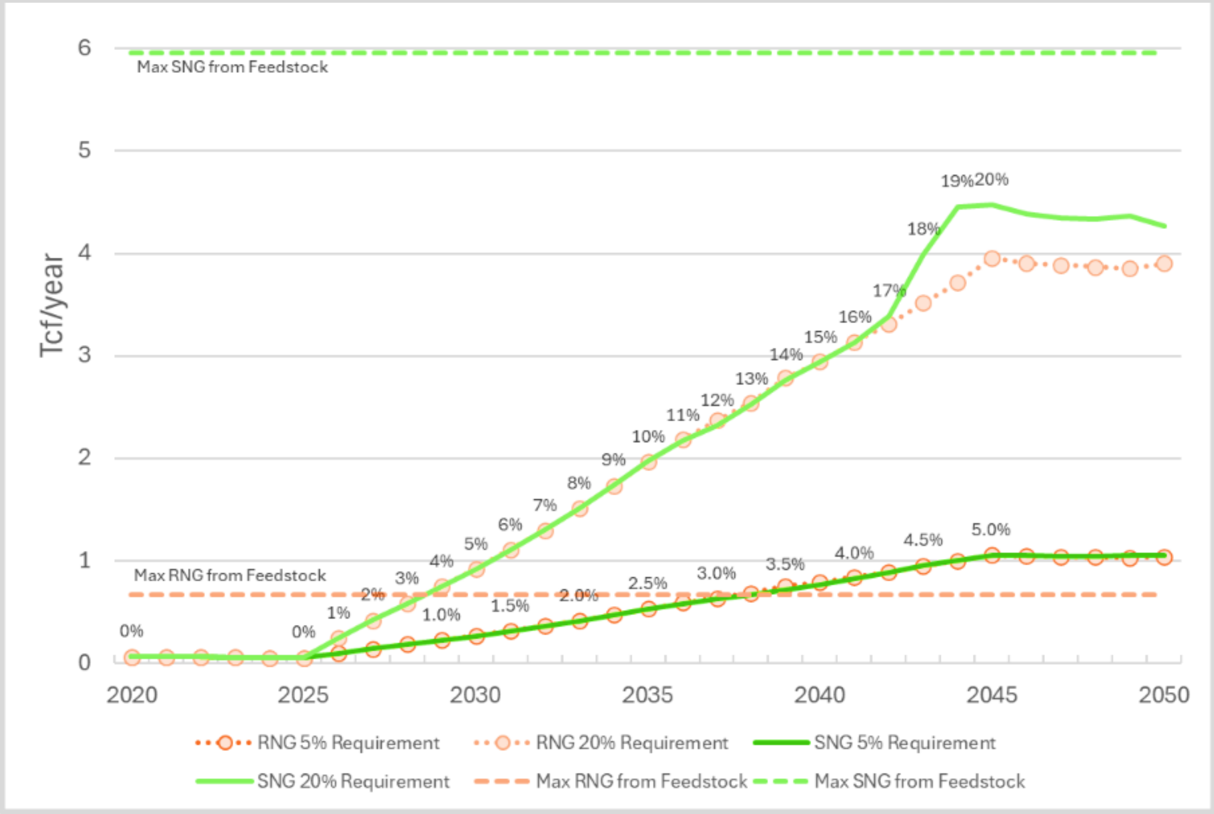


Figure 27. Gulf Coast RNG/ SNG requirements and feedstock availability

To meet these blending targets, additional feedstock would need to be sourced from outside the region, or alternative RNG feedstocks (e.g., dairy waste, wastewater) should be considered. Enhancing the feedstock supply chain will be critical to enable wider RNG deployment in the Gulf Coast.

Facility Size Discussion

Additional production facilities will need to be constructed in the region to achieve these blending rates in the Gulf Coast region. The scaling of facilities will likely be a wide distribution, with some facilities representing large, centralized facilities that can process feedstocks from multiple sources, while others will be for smaller, low-blend end uses. While not considered in this study, co-processing production facilities for RNG and SNG production pose an opportunity to scale regional production more effectively. The selection of technologies and processes that can accommodate a wider range of feedstock types may offer more long-term benefits when diversifying feedstocks becomes of interest.

Blending Rates

This section has evaluated total natural gas system blending scenarios with emerging fuels, rather than assessing blend rates by various end use sectors. While an idealized scenario would present blends rates by end use sector, this calculation would overlook the reality that various end users share the same distribution mains, resulting in shared blend rates among local end users.

This total system blend analysis accounts for the displacement of natural gas to accommodate volume changes due to emerging fuel blends and assumes a range of blend rates among different end users. Depending on the locations and scale of production facilities relative to end users, a wide range of blend rates could be established for specific end users.

CBA Results

The focus of the CBA is to estimate the level of financial incentive each emerging fuel would need to reach cost parity with conventional natural gas. This key metric highlights strategic policies and investments that can accelerate the adoption of these emerging fuels. The required incentives needed to adopt emerging fuels are summarized as fuel specific values at the regional level.

Required Incentives by Fuel Case

The incentives described in this section represent the economic offset required for the given fuel to reach cost parity with natural gas, summarized below in **Figure 28**.

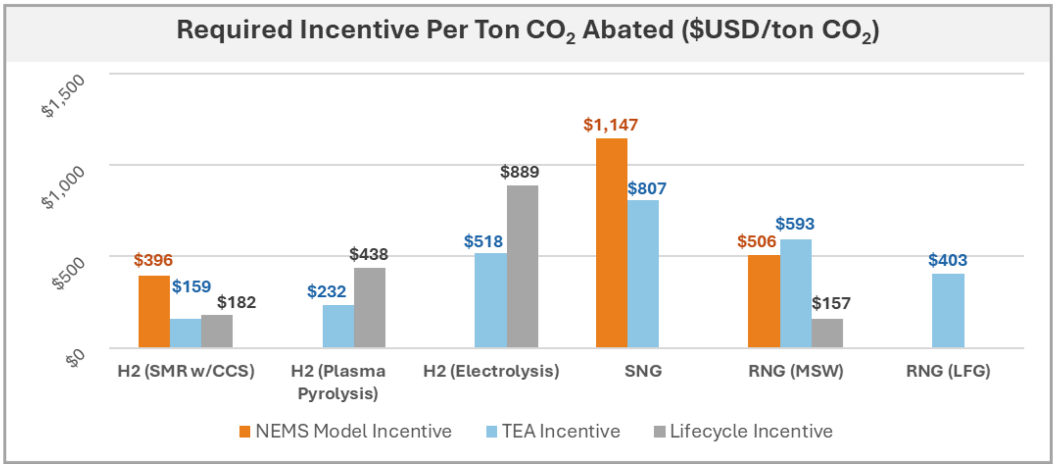


Figure 28. Required incentives for emerging fuels ($/ton of CO_2 avoided)

The levelized cost of natural gas is a critical parameter of the TEA, NEMS and LCA required incentive calculations. The TEA required incentive calculations assumed a levelized cost of natural gas to be $4.75/MMBtu whereas the OL-NEMS required incentive calculations consider the modeled natural gas prices anticipated with the OL-NEMS reference case annualized market assumptions. For context, a natural gas price of $4.75/ MMBtu most closely resembles the 2023 average price of natural gas in Mississippi ($4.77/MMBtu), which is nearly double the average 2023 natural gas price in Texas ($2.63/ MMBtu) and nearly half the average price in Arkansas ($9.13/ MMBtu).

Notably, NEMS assumes higher natural gas prices, which results in higher calculated required incentives than the TEA and LCA methodologies. Natural gas prices modeled in OL-NEMS Reference case from 2023 to 2035 average ~$5.58/ MMBtu NG, which far exceeds the prices observed in Texas and Louisiana. Thus, the true required incentives for emerging fuels in Texas and Louisiana will possibly be lower than the OL-NEMS, TEA, and LCA calculated required incentives.

Another methodology difference between the NEMS, LCA, and TEA required incentive calculation applies to the CI assumptions. The Lifecycle incentive calculations incorporate a fuel case specific CI, whereas the NEMs and TEA treat the fuel case CI as zero. Thus, the TEA and NEMS required incentive calculations best reflect differences in fuel case specific levelized costs rather than carbon intensities. However, the CI of NG is assumed to be ~16.38 MMBtu per ton of CO_2e for all incentive calculations.

These incentives illustrate the range of economic stimuli necessary to promote the adoption of some of the technologies being explored by this study. These quantified incentives represent a "break-even" CO_2 emissions price, which can be interpreted either as a cost avoided in the case of a tax, or an additional revenue stream in the case of a credit.

The CBA concludes:

1) **Incentives are needed to enable most H_2 technologies to be economically competitive.** Furthermore, reforming technologies may be a viable path forward for low-carbon H_2 in the future, provided that further research is able to reduce costs through a combination of lower feedstock costs, higher yields, lower technology costs, and more robust supply chains.
2) **Based on the LCA findings, most H_2 pathways produce significantly lower CO_2 emissions compared to natural gas**, with required carbon incentives ranging from $400 to 900/ton of CO_2 avoided. Plasma pyrolysis, from the TEA perspective, resulted in a net cost of about $18.44/MMBtu, the lowest of all renewable pathways, only slightly behind natural gas-based reforming technologies ($14.44/MMBtu for SMR and $13.47/MMBtu for ATR). While the LCA showed increased required incentives for all cases, plasma pyrolysis' required incentive remains the lowest of the H_2 cases at $437.71/ton of CO_2 avoided.
3) **The SNG cases were the highest cost of all pathways considered**. Notably, the LCA results reflect no economic benefit of producing SNG in lieu of fossil-based natural gas. Due to the complex supply chain requiring two inputs from highly costly sources (H_2 from electrolysis using low-carbon electricity sources and CO_2 sourced from a point source), the TEA and NEMS results estimated required incentives for SNG in the most economical cases are $807.35/ton CO_2 and $1,146.58/ton CO_2, respectively. However, further modeling with a lower-cost H_2 feedstock may reveal that SNG could be a more viable and competitive pathway.
4) **The RNG cases required lower incentives.** Firstly, the NEMS model showed that delivered RNG prices of $25/MMBtu are possible in the long-term, yielding required incentives of around $350/ton CO_2. Note that these prices are marginal prices, which are the costs to produce the next molecule of RNG. Since the NEMS

model selected the RNG production pathway that utilizes free MSW as the lowest cost method, the marginal costs in subsequent years rapidly decline once the production facility is built. The TEA yielded estimated required incentives of around \$600 to \$1,600/ton CO_2. This wide range is likely due to the TEA results being based on small-scale gasifier technology (~50 to 400 tons per day), which are expensive due to high capital costs and unfavorable economies of scale. A CO_2 incentive of \$156.91/ton of CO_2 was estimated, owed primarily due to the highly negative CO_2 emissions associated with this pathway. These results suggest that RNG has the potential to begin replacing fossil-based natural gas in the Gulf Coast due to the region's abundant supply of MSW and the relatively economical cost of biodigesters.

Levelized Fuel Cost vs. Carbon Intensity

The CBA required incentive calculations were determined at the regional level and considered fuel-specific carbon intensities and levelized costs. However, it is also important to consider state-level differences that may impact the outcomes of specific incentives for emerging fuel adoption.

Figure 29 compares state differences in fuel pathway levelized costs (\$/kg fuel) to respective carbon intensities (CIs) (kg CO_2e/ kg fuel) for lowest cost H_2, SNG, and RNG pathways. The ovals visualize the variability of levelized costs and Cis for each pathway. While there are a wide range of CIs and levelized costs for each Gulf Coast state, H_2 pathways have notably lower levelized costs and CIs in comparison to the SNG and RNG pathways considered in this study.

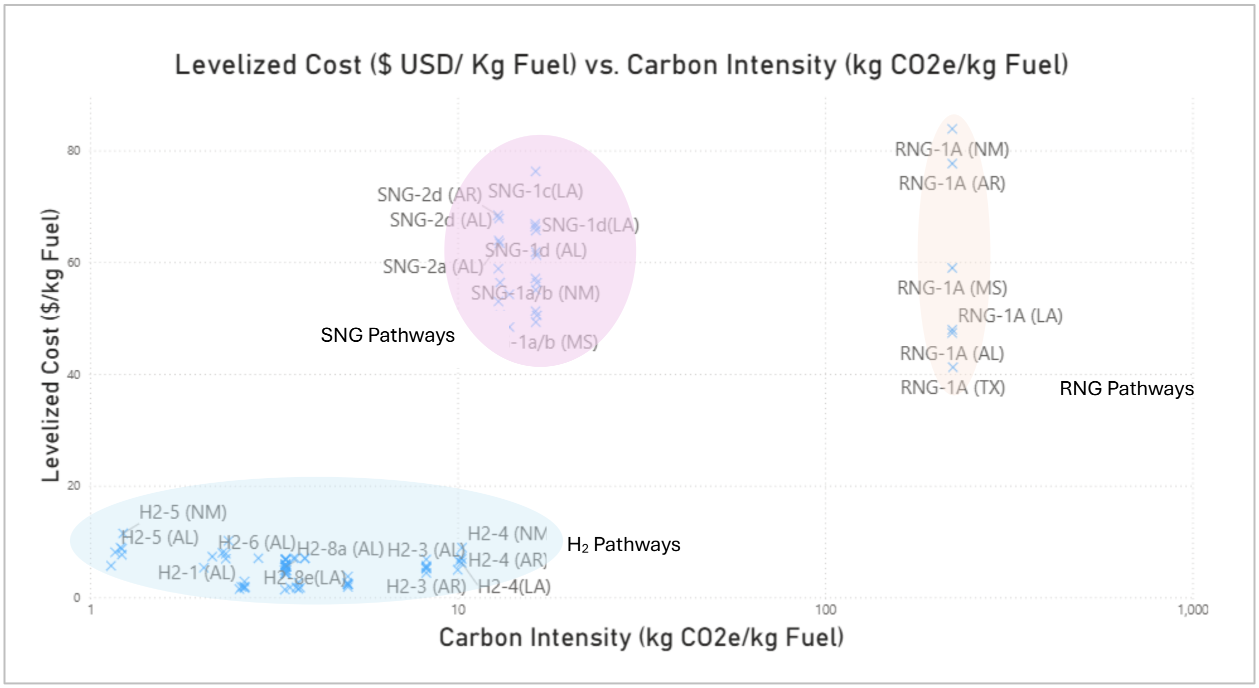


Figure 29. Fuel pathway levelized cost vs. carbon intensity (state-level)[4]

The lowest-cost H_2 production pathways in the Gulf Coast are natural gas SMR with CCS, ATR with CCS, and plasma pyrolysis. These options benefit from the region's low-cost natural gas and the ability to scale to commercial capacities. Electrolysis remains a high-cost option in the region (case H2-8), primarily due to a combination of high capital expenditures and electricity-related operating costs, driven by price volatility and intermittency of renewables. As a result, electrolysis-based H_2 is currently less competitive without targeted incentives or low-cost electricity available. CI-based incentives will be an important driver for electrolytic H_2 in the Gulf Coast, as it yields lower CIs than H_2 produced via natural gas SMR/ATR with CCS and natural gas pyrolysis (**Figure 30**).

[4] Note, Carbon Intensities for RNG converted from Kg CO2e/ MJ with assumed lower heating values used for the RNG cases to be 14.54 MJ/kg for RNG-1A.

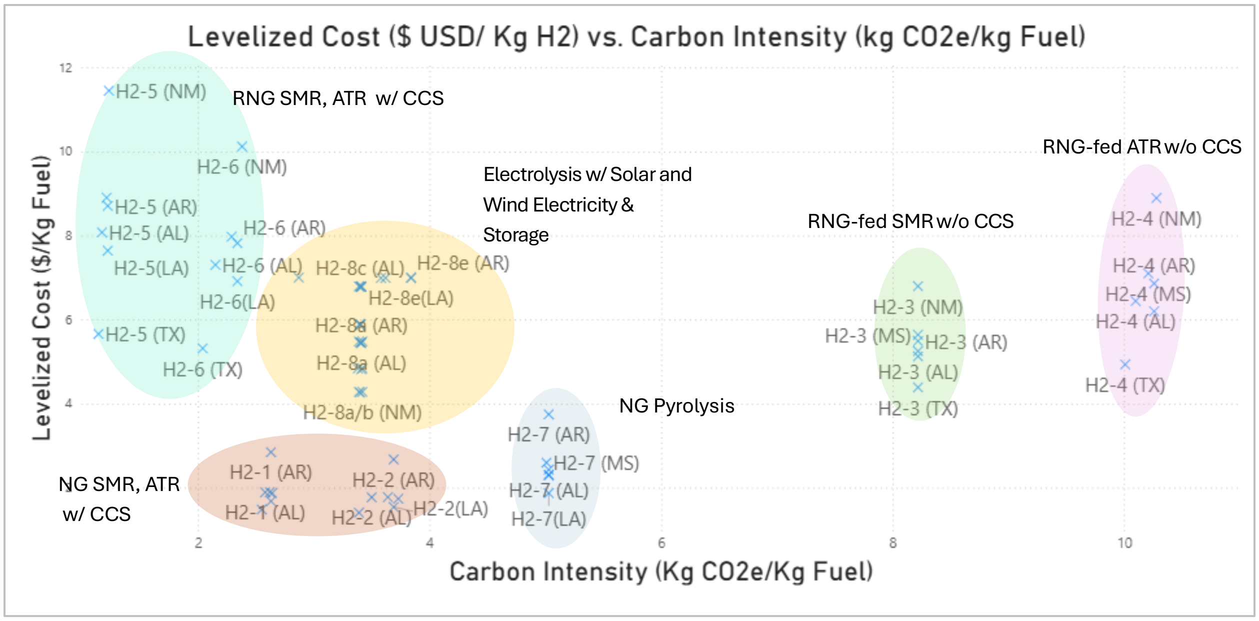


Figure 30. Levelized H_2 cost vs. carbon intensity (state-level)

The CI of H_2 produced via electrolysis in Alabama is approximately 32% less than H_2 produced via pyrolysis but costs approximately 14% more. In contrast, there is a minimal difference in CI for H_2 produced via electrolysis in Arkansas compared to H_2 produced via natural gas SMR/ATR with CCS. This suggests that natural gas SMR/ATR with CCS is more economical even with CI-based incentives.

Natural gas SMR and ATR with CCS are currently the most cost-effective H_2 production routes and support meaningful emissions reductions. While electrolysis remains expensive, its decarbonization potential increases with access to low-cost renewables and grid decarbonization. Among the Gulf Coast states, Texas stands out with the lowest H_2 production cost ($1.40/kg via ATR + CCS), while Arkansas sees the highest at $2.67/kg, largely due to resource variability and scale limitations.

For several H_2 pathways, levelized costs for a single pathway differ more strongly between states than calculated carbon intensities (**Figure 30**), which demonstrate less than a 7% difference between state-level H_2 pathway CIs. For instance, H_2 produced via natural gas SMR/ATR with CCS and natural gas pyrolysis demonstrate the greatest difference in calculated state-level levelized H_2 pathway costs, which indicates an opportunity for Texas and Louisiana to achieve lower overall costs from CI-dependent incentives.

Similar to the state-level trends observed for H_2 pathways, the levelized costs of RNG and SNG pathways show greater variability across states. These differences are most significantly observed with capital costs and variable O&M specific to each state. Due to higher levelized costs across all four RNG cases considered, New Mexico is likely to most benefit from CI-based incentives for RNG and SNG production.

RNG pathways show the widest variation in emissions regardless of state, with cases ranging from net-negative (RNG-1B) to relatively high GHG intensity (RNG-1A), highlighting the importance of technology choice and feedstock. Utilizing waste biomass (e.g., MSW) and landfill gas helps reduce landfill methane emissions, a potent GHG, while producing usable fuels. Moreover, integrating H_2 blending with natural gas displaces fossil fuels in the energy mix, supporting further decarbonization goals. While RNG supports waste valorization and localized fuel production, high costs and limited scalability constrain its contribution to large-scale H_2 markets. SNG pathways generally exhibit higher emissions than H_2 pathways but still offer reductions compared to conventional natural gas when CCS is applied (**Figure 31**).

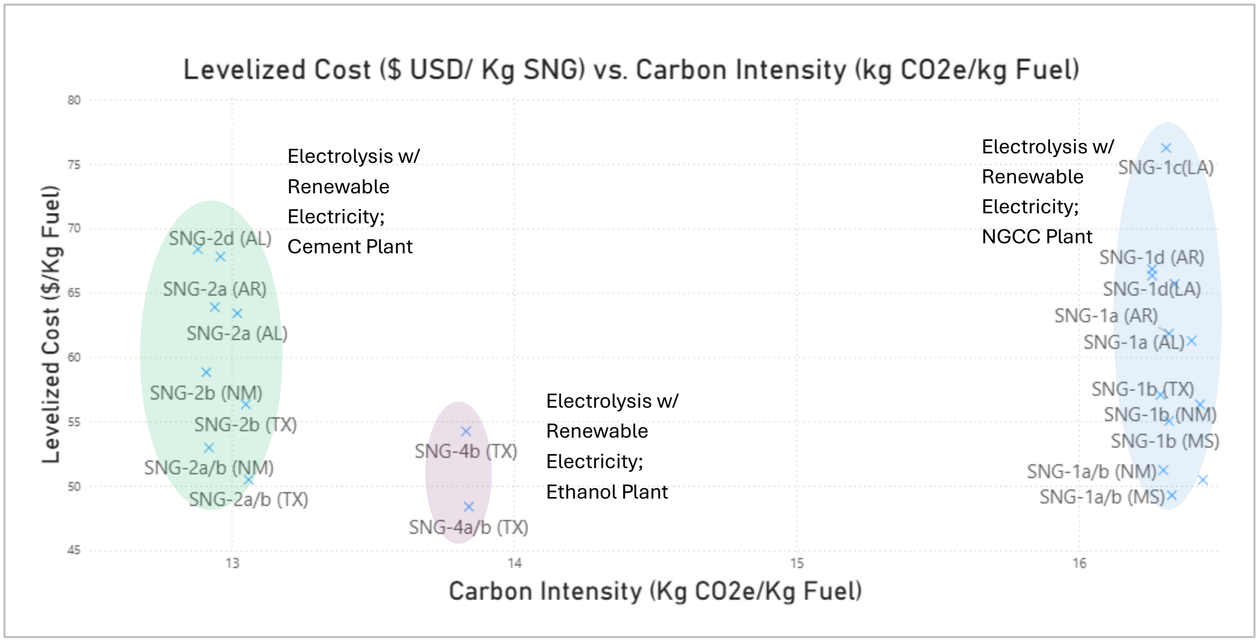


Figure 31. Levelized SNG cost vs. carbon intensity

Among the emerging fuel pathways evaluated in this study, SNG offers the least emissions reduction benefit relative to the level of incentives required on a kg of fuel basis. Electrolytic SNG costs are largely driven by the price of H_2 feedstock, which varies across the Gulf Coast states (**Figure 31**). SNG produced via electrolysis which is co-located with a CCS source facility (cement, ethanol) and fed renewable electricity is found to be most cost-effective in Texas and New Mexico.

CBA Summary

The Gulf Coast is among the most energy-rich regions in the U.S., with over 1.3 Tcf of natural gas and 55 million tons of biomass. Texas leads the nation in renewable power generation, providing significant opportunities for future electrolysis deployment. The region's dense oil and gas infrastructure, including H_2 pipelines in Texas and Louisiana, enhances the viability of large-scale deployment and interregional fuel distribution.

Blending H_2 into existing natural gas pipelines emerges as a near-term pathway for H_2 deployment, leveraging existing infrastructure and lowering transition costs. Based on the CBA, the most cost-effective H_2 technologies will be fossil-based H_2 production via SMR or ATR with CCS and plasma pyrolysis.

Additionally, RNG produced from MSW demonstrated a cost advantage. These three technologies offer the best balance of cost and scale, especially in Texas, which has abundant resources and infrastructure. However, when including a requirement for decarbonization, RNG production from either MSW or LFG offers co-benefits like methane mitigation and carbon negativity to produce drop-in fuels, offering carbon-negative fuel production without significant infrastructure upgrades. However, these pathways need policy support to offset the high production cost.

The SNG pathways considered will require the most significant incentives compared to the RNG and H_2 cases. SNG produced via electrolysis with methanation that is co-located with a NGCC or Ethanol plant in Texas is found to have the lowest levelized costs. There is notably high variability in SNG levelized costs between states, driven by the cost of electrolytic hydrogen. Followed by Texas, Mississippi, New Mexico have some of the lowest levelized costs for SNG via electrolysis at a NGCC plant, whereas Louisiana and Arkansas have the highest respective costs.

Major reductions in electrolysis technology costs which can particularly address the high variable O&M costs would potentially reduce the necessary incentives for electrolytic SNG to reach cost parity with natural gas in the Gulf Coast. This high variable O&M for electrolysis would need to be reduced either by major reductions in renewable electricity prices or electrolysis technology efficiency improvements.

Finally, the Gulf Coast region offers a strategic alignment of infrastructure and resources that positions it as a strong candidate for becoming a national hub for low-carbon fuel production and distribution. Its existing industrial base, abundant feedstocks, and existing H_2 pipelines provide a solid foundation for scaling up emerging fuel adoption. From a policy perspective, implementing regulatory blending mandates and targeted financial incentives could significantly improve the cost-effectiveness of higher-cost pathways such as electrolysis, RNG, and SNG. Ultimately, these measures would support the development of a more diversified and resilient energy system. The role of existing and additional infrastructure in support of fuel expansion and integration with existing natural gas infrastructure is explored in the following section.

Current State of Infrastructure

The Gulf Coast operates the most oil and gas infrastructure in the nation, with the bulk of pipelines, wells, hubs, and substations in Texas, Louisiana, and Mississippi (**Figure 32**). The region also leads in H_2 and CO_2 pipeline developments, with nearly 1,600 miles of H_2 pipeline networks serving Texas and Louisiana (Texas Hydrogen Alliance, n.d.).

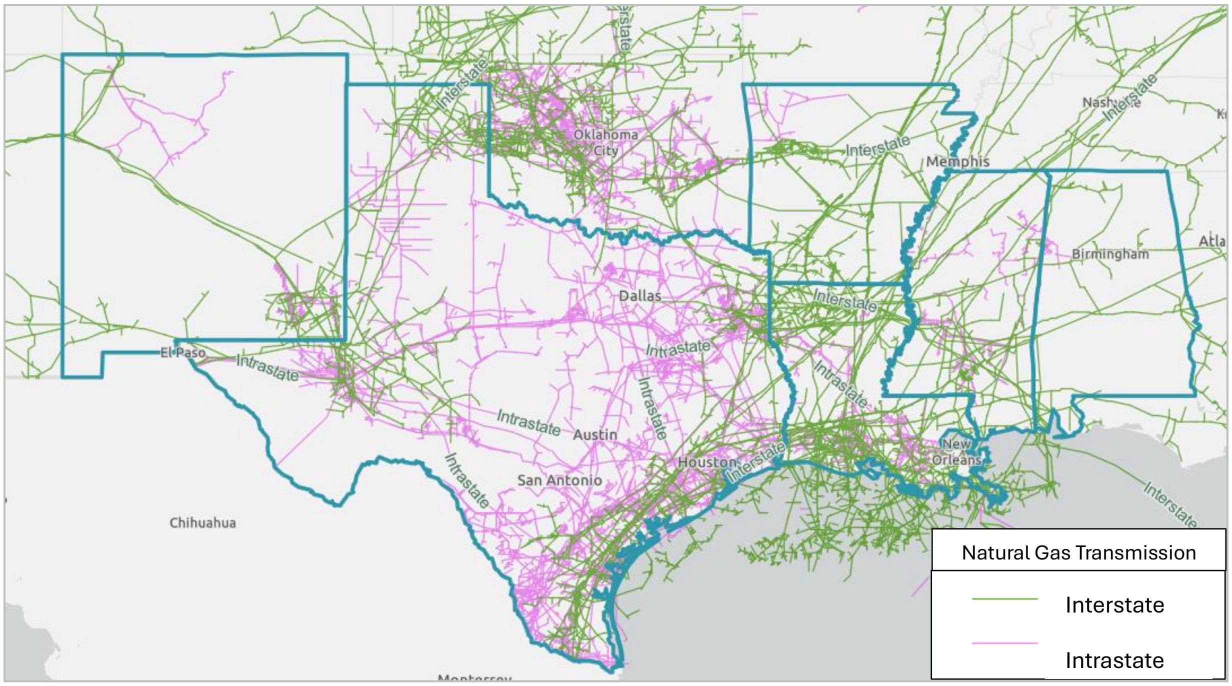


Figure 32. Natural gas transmission pipeline infrastructure in the Gulf Coast

Natural gas infrastructure continues to evolve in the region, with multiple planned expansions and upgrades in progress, and new pipeline construction projects occurring in Texas, Louisiana, and Mississippi. **Figure 33** highlights the investments announced in 2025 to increase natural gas capacity across the Gulf Coast.

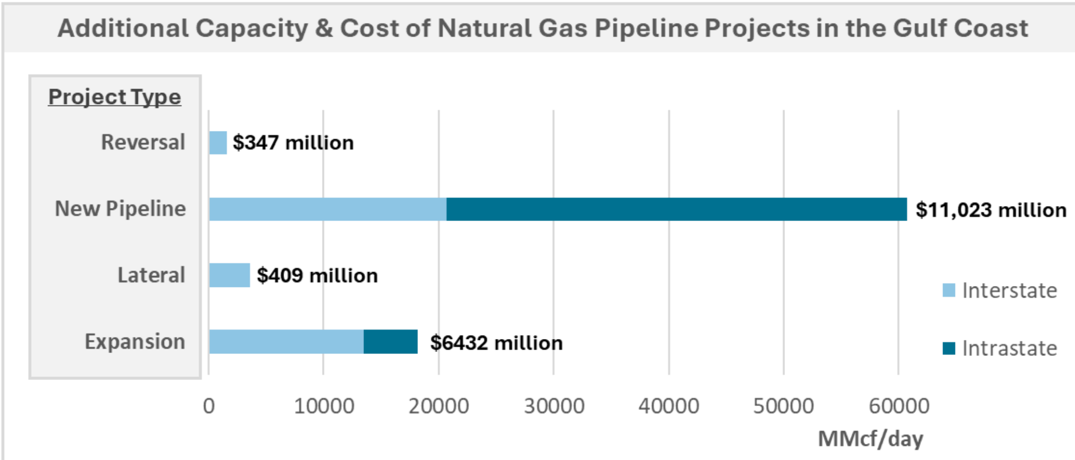


Figure 33. Additional capacity from announced natural gas pipeline projects for the Gulf Coast (as of April 2025) (Energy Information Administration 2025)

A majority of states in the Gulf Coast depend on a steady supply of Texas and Louisiana coal, oil, and gas exports to fulfill their energy needs (ICF International 2016). A map of the general oil and gas product flows is shown in **Figure 34**.

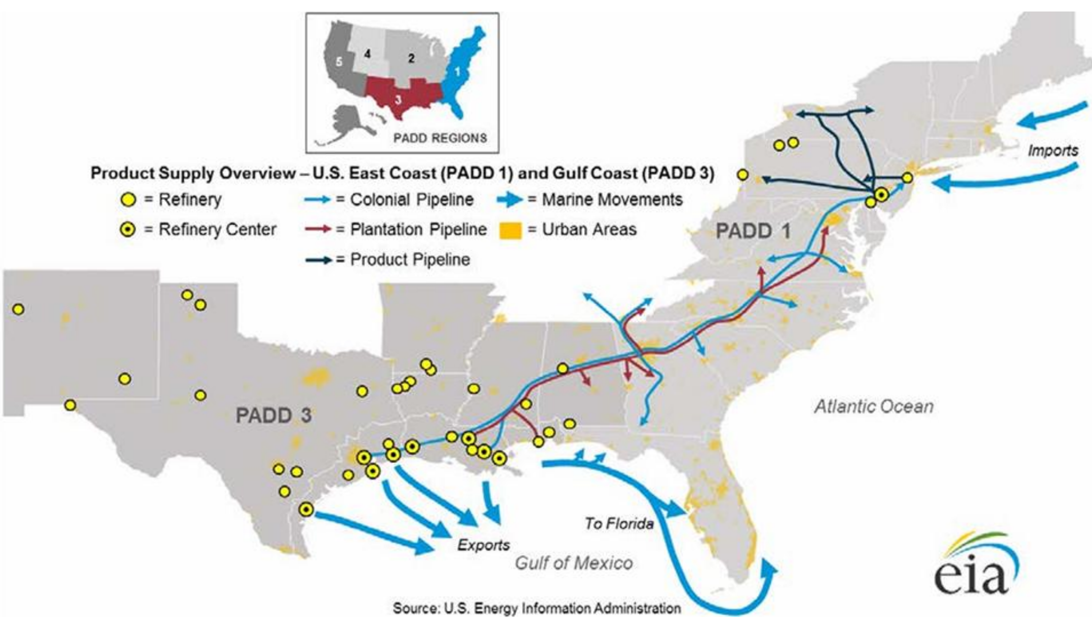


Figure 34. Petroleum refineries and key product flows in the Gulf Coast and East Coast

Natural gas production in Texas and Louisiana also serves a critical role in the East Coast and Midwest states. For instance, the 9,400-mile TC Energy ANR transmission pipeline connects producers in Louisiana and Texas to consumers in Wisconsin, Michigan, Ohio, and Illinois, and provides a peak capacity of 10 Bcf/day (Energy, 2025).

Figure 35 below summarizes the existing natural gas infrastructure in the Gulf Coast region that delivers H_2, CO_2, RNG and SNG (PHMSA, Pipeline Mileage and Facilities, 2024). Texas is the leading state with the most infrastructure, followed by Louisiana and New Mexico.

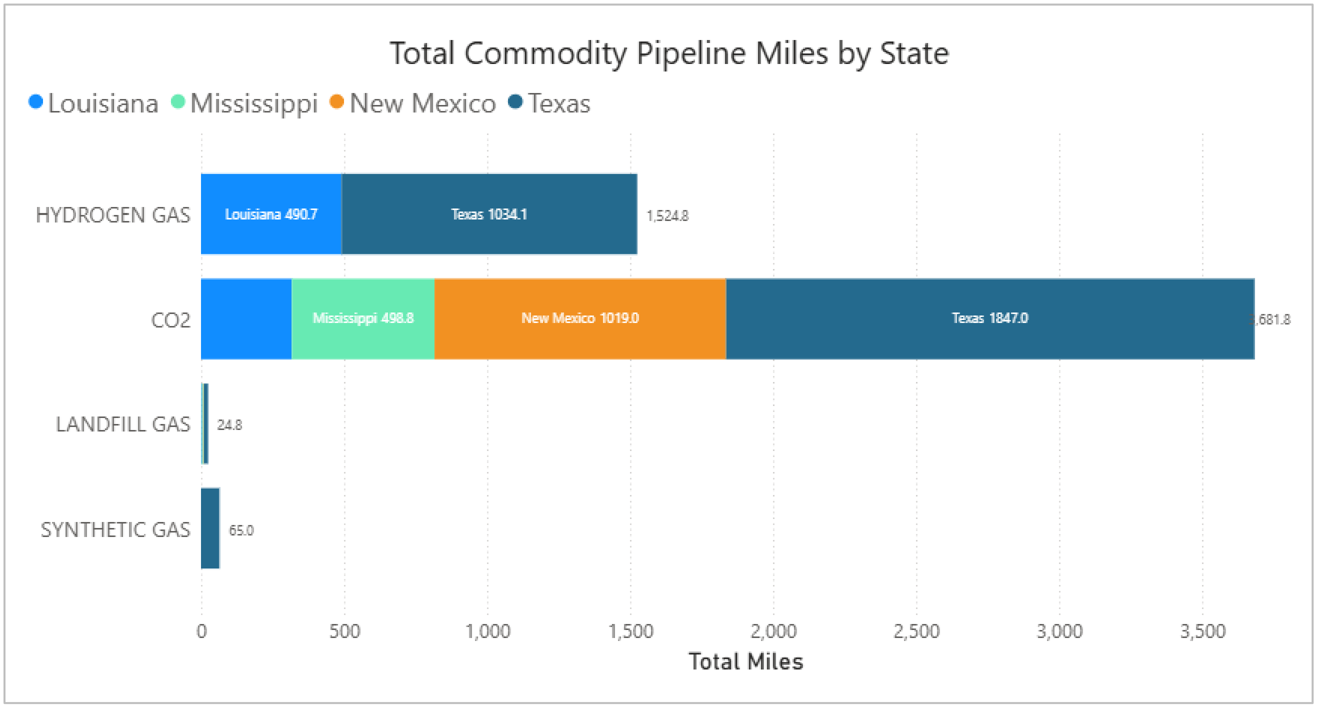


Figure 35. Existing H_2, RNG, SNG, CO_2 pipelines in the Gulf Coast

Two major clusters of available CO_2 pipelines are centered in Texas and Mississippi, with the Texas cluster extending across New Mexico and into other neighboring states and the Mississippi cluster extending into Louisiana (U.S. Department of Energy 2024). The potential for carbon capture hubs is strong, especially in New Mexico, due to the highly active oil and gas industry in the Permian Basin and abundant wind and solar resources (U.S. Department of Energy 2024). There is increasing interest in developing more efficient designs of carbon capture technologies, which can recover fugitive sources, especially originating from oil and gas operations. Direct air capture technologies scaled in the Gulf Coast's oil and gas sector have the benefit of proximity to existing natural gas pipeline networks, which may be retrofitted to deliver CO_2 in the future.

Extensive industrial infrastructure can support the expansion of CO_2, and H_2 supply in the region. The DOE predicts that the Gulf Coast could become a center for various carbon capture, transport, and storage hubs and H_2 hubs through the sharing of this existing infrastructure, which could lower transportation costs of these gases by two-thirds (DOE, 2024). Note in **Figure 36** that H_2 hub locations are optimally considered in direct vicinity of natural gas industrial facilities and natural gas infrastructure. For instance, the HyVelocity Hydrogen Hub, as well as other H_2 hubs in Texas will leverage existing infrastructure and develop new pipelines to expand the transport and use of low carbon H_2 in the region.

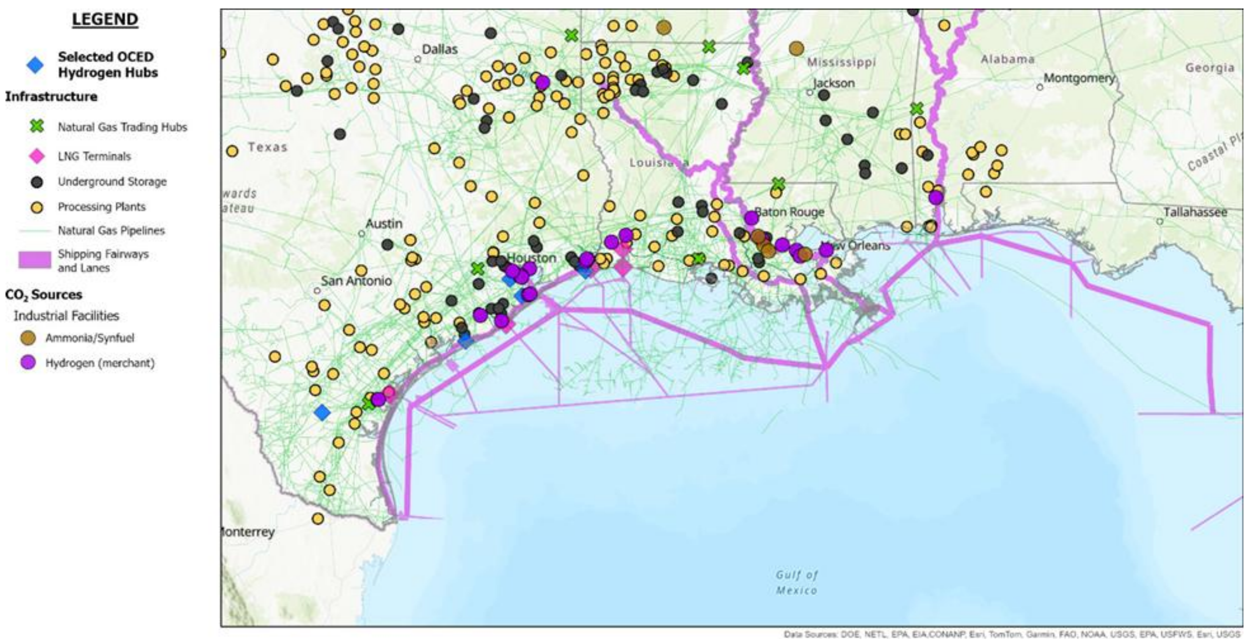


Figure 36. LNG, H_2, and NH_3 production and supply lines

The Gulf Coast's extensive natural gas and LNG infrastructure, combined with strong support for H_2 hubs and proximity to major industrial centers, makes it a prime region for H_2 infrastructure investment. These advantages reinforce the conclusion that the Gulf Coast could be effectively leveraged to supply usable H_2 through gasification technologies.

Underground Storage (UGS)

UGS plays a critical role in maintaining the reliability and resiliency of energy systems. For decades, UGS has been instrumental in supply and demand balancing throughout the year, providing protection against excess demand, market volatility, extreme weather events and other supply chain disruptions. During winter months, for instance, UGS enables rapid withdrawal of natural gas to meet heightened heating demands, preventing supply shortages and reducing the risk of price surges. Additionally, as renewable energy sources like wind and solar grow, UGS serves as a vital backup, filling in the gaps when renewable output falls short, such as during periods of low wind or solar irradiance.

In the Gulf Coast, UGS plays a strategic role in supporting the LNG export industry, which mitigates impacts of variable production and demand. High-deliverability facilities, particularly salt caverns, allow for quick switching between gas withdrawal and injection, providing both local businesses and global markets with a steady, responsive supply.

Louisiana, Texas, and Mississippi contain the highest designed working gas storage capacities in the Gulf Coast (**Figure 37**). Additional capacities are provided by Alabama, Arkansas, and New Mexico.

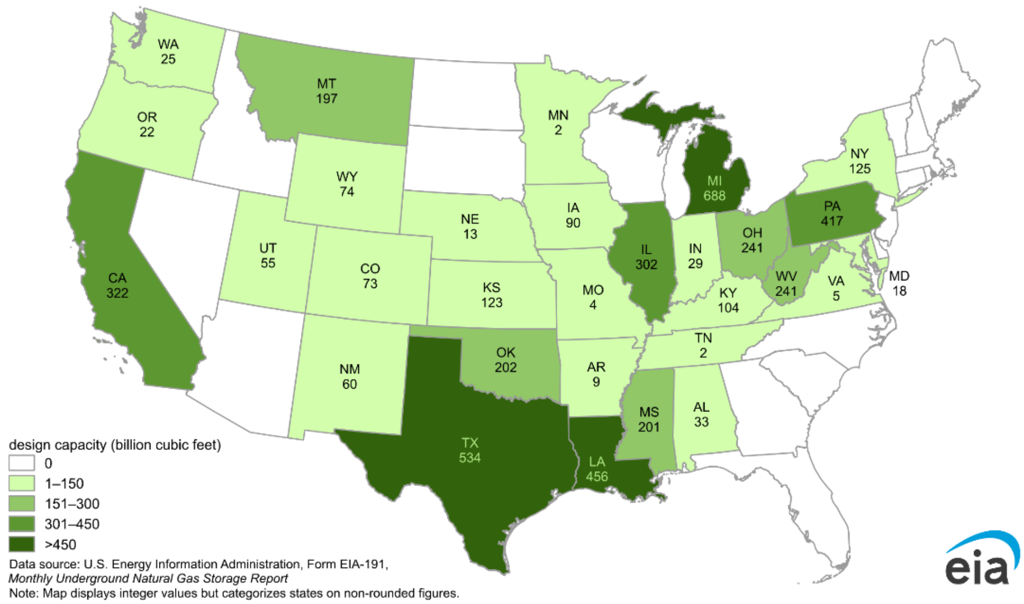


Figure 37. Design working natural gas capacity by state in November 2023; Source: (U.S. Energy Information Administration, n.d.-b)

These UGS facilities operate under a comprehensive policy framework aimed at ensuring safety, environmental protection, and reliable service. Federal oversight by FERC and PHMSA, along with state-level regulations, sets strict standards for UGS design, operational integrity, and environmental safeguards, including well integrity protocols, pressure monitoring, and regular inspections to prevent methane leaks and minimize risks associated with subsurface storage.

In the Gulf Coast region, specific policies protect aquifers and coastal environments, often exceeding federal requirements. Recent policy developments have also emphasized the need to strengthen UGS infrastructure against single-point-of-failure risks and to enhance resilience to extreme weather, which is crucial in the Gulf Coast.

UGS: Hydrogen Considerations

As UGS increasingly supports the adoption of emerging fuels, additional regulatory considerations for facilities repurposed for H_2 storage or exploring carbon sequestration are necessary. Such adaptations may require updated standards for material compatibility, well design, and monitoring to prevent environmental impacts. Additionally, any further development of storage reservoirs and caverns to support a H_2 economy would need to account for H_2's energy density being one third that of natural gas. Together, these policies not only ensure safe, reliable UGS operations but also support innovation and adaptability as UGS evolves to meet the dual demands of energy stability and decarbonization goals, positioning the Gulf Coast as a model for balancing stringent safety standards with flexibility in a transitioning energy landscape.

Looking ahead, research into optimizing UGS will help better serve vulnerable areas and support decarbonization goals. Repurposing UGS for H_2 storage could significantly bolster low-carbon energy storage markets, while future developments may even enable the use of carbon dioxide in UGS operations.

Regional Energy Reliability

Reliable energy systems can consistently deliver energy to customers, with limited interruption and with efficiency. Dependency on electric infrastructure strongly influences energy reliability in the Gulf Coast, as electric transmission infrastructure can require additional unexpected maintenance periods, which lead to increased disruptions for end users.

Each of the Gulf Coast states consume similar ratios of natural gas to electricity, with the exception of Louisiana. Electricity grid infrastructure across the U.S. operates at an estimated utilization rate of around 71.4% as of Q1 2025 (FRED, 2025). In the Gulf Coast, grid utilization varies by state but generally aligns with or slightly exceeds the national average, particularly in high-demand areas like Texas, where the ERCOT grid frequently operates near peak capacity during summer months. The natural gas pipeline systems in the Gulf Coast tend to run at higher utilization around 75 – 90% with peak flows along key interstate routes, such as in Texas and Louisiana, often reaching 90–100% utilization (Baylin-Stern & Berghout, 2021), (Mccartney, 2024). Rising energy demand is placing increasing stress on the Gulf Coast's power grid, especially in Texas, where ERCOT forecasts peak demand to rise from around 85 GW in 2023 to as high as 145–218 GW by 2030 (Skidmore, 2025).

The natural gas pipeline network serves as a critical backup energy source by supplying fuel for gas-fired power plants, which generate over 70% of electricity in states like Louisiana and Mississippi, enabling decentralized energy generation closer to demand centers. High pipeline utilization indicates the system's adaptability and capacity to meet peak loads, making it an important buffer during periods of electric grid stress. By complementing the electricity grid with high-deliverability natural gas, the Gulf Coast can enhance its overall energy system reliability amid surging industrial demand.

State Energy Consumption Trends

Significant in-state energy production is another major component of energy reliability. **Figure 38** highlights key statistics regarding state energy consumption.

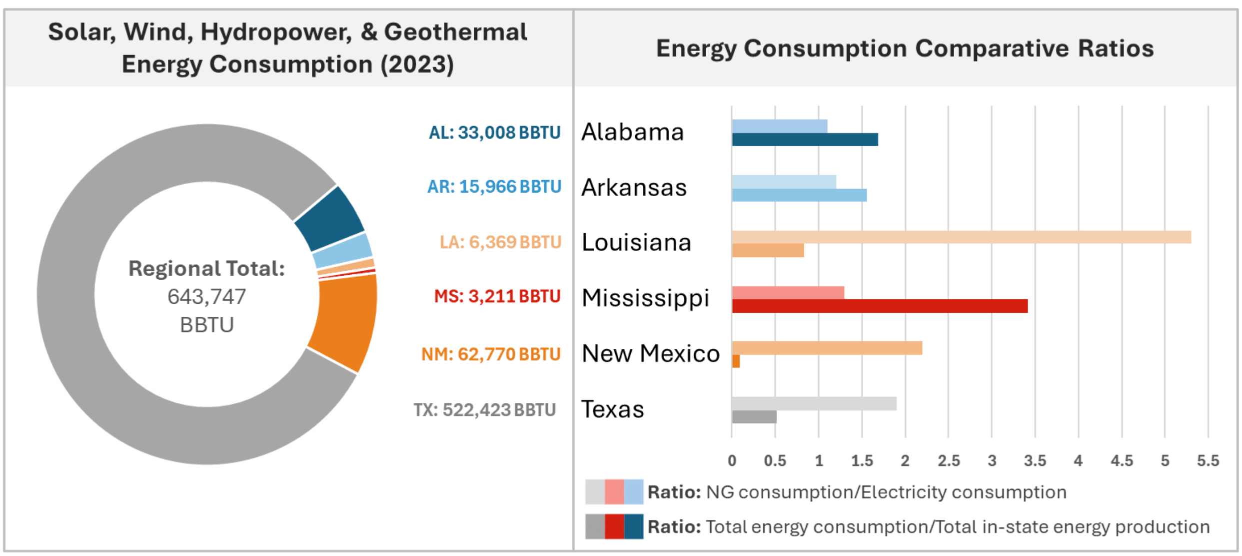


Figure 38. Energy consumption statistics by state (EIA, 2024)

Texas, New Mexico, and Louisiana have lower ratios of total energy consumption compared to in-state energy production. States that have a higher total energy consumption to production ratio, such as Mississippi, Alabama, and Arkansas, can particularly benefit from scaling emerging fuels to improve energy reliability in the future. In the Gulf Coast region, higher renewable energy consumption generally corresponds with a lower ratio of total energy consumption to in-state production for each state. This trend is largely driven by the significant development of solar and wind projects across the area.

Energy Disruptions and Weather Impacts

The reliability of natural gas infrastructure is especially important in Louisiana, Texas, and Mississippi, all of which experience significant power outages in comparison to other states in the country.

Due to the extreme weather events that can occur along the Gulf Coast, weatherization of infrastructure is needed for both electric and natural gas infrastructure. In 2020, Hurricane Laura disrupted operations at two major LNG facilities in Louisiana, causing significant delays and economic losses. In 2021, a series of severe winter storms in Texas led to widespread failures across the energy system, resulting in life-threatening shortages of electricity, heating, and other essential services. These events underscore the urgent need to weatherize vital components of the energy supply chain further illustrates the financial impact of these billion-dollar disasters across states.

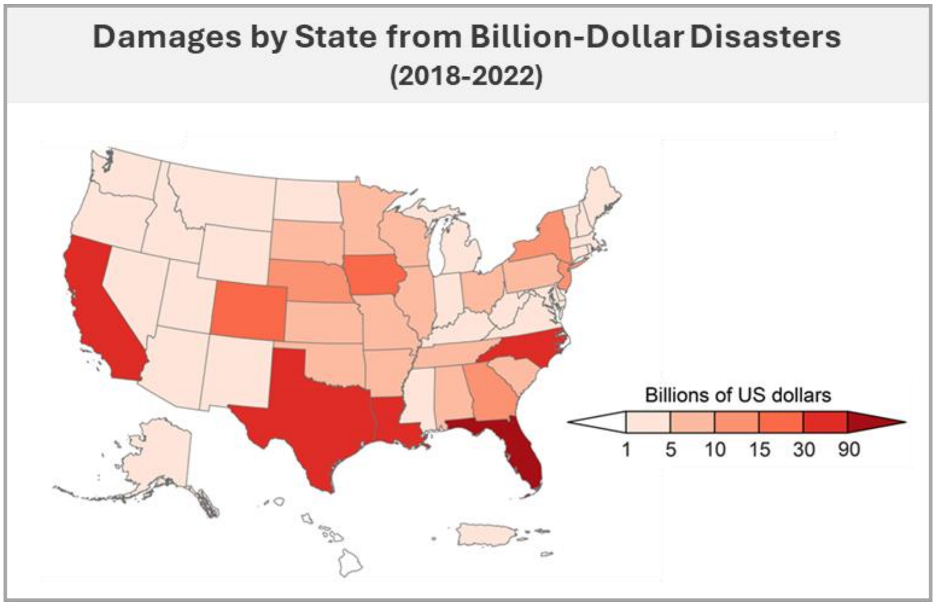


*Figure 39. Damages by state from billion-dollar disasters (e.g., winter storms, droughts, floods, or wildfires); Source: (*Fifth National Climate Assessment *2023)*

Weatherization of natural gas infrastructure involves reinforcing pipelines, compressor stations, processing facilities, and LNG terminals to withstand high winds, flooding, saltwater exposure, and extreme temperatures. Key measures include burying pipelines more deeply, insulating or heat-tracing critical components, elevating control systems above flood levels, and ensuring access to reliable backup power. These efforts help maintain operational integrity during both tropical and cold-weather events.

Beyond production and processing, the resilience of natural gas distribution systems is equally important. Local networks of pipelines, regulators, and metering stations are vulnerable to freezing and power outages, especially during extreme cold. When these systems fail, gas pressure can drop dramatically, disrupting service to homes and businesses, particularly in regions where natural gas is the primary heating source.

In response, utilities and regulators across the Gulf Coast are beginning to adopt more rigorous weatherization standards. For example, following the 2021 winter storm, Texas oil and gas regulators implemented new requirements mandating that operators report annually on their weatherization commitments to the Railroad Commission of Texas (Ferman, 2022). These policies represent a growing recognition of the need for proactive infrastructure hardening and emergency planning.

As part of a broader resilience strategy, attention is also turning to the role of UGS and enabling end users to access multiple fuel options. UGS enhances the energy system's reliability and resiliency by supporting quick responses to supply-chain disruptions or sudden supply and demand shifts. The Gulf Coast's substantial UGS capacity is essential for swiftly adapting to such events, ensuring a reliable natural gas supply even during extreme weather. This role of UGS becomes increasingly critical as climate change impacts and risks intensify across interconnected sectors and regions. In addition to expected seasonal variability, the Gulf Coast region in particular is projected to have higher energy needs over time to adapt to climate change, as shown in **Figure 40**.

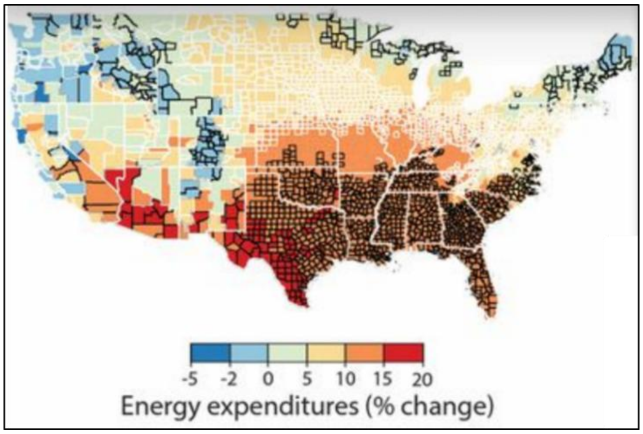


Figure 40. County-level median values for average 2080 to 2099 RCP8.5 impacts. Southern states are predicted to experience more negative climate impacts, including an increase in energy demand to adapt to climate changes; Source: (Hsiang et al. 2017)

Regional Pipeline Readiness for H_2, RNG, SNG, and CO_2

The suitability of transporting H_2, RNG, SNG, and CO_2 in natural gas infrastructure is dependent on the characteristics of the pipeline system. There are a number of key considerations for integrating these emerging fuels. While not an exhaustive list, the following highlights the primary factors that operators should consider when assessing their systems:

- Material compatibility of the entire delivery system
- Pipeline system capacity
- Midstream and end-use equipment compatibility
- CO_2 pipeline-specific challenges
- Importance of production facility locality to end use

Challenges with Infrastructure Materials and Pipeline Modernization

Natural gas delivery infrastructure utilized across the U.S. incorporates highly heterogeneous networks of different pipe materials and ages. Midstream and downstream natural gas companies have made significant efforts to reduce pre-1970s pipe, particularly cast-iron and bare steel. However, pipeline materials such as cast-iron, bare steel, and vintage plastics (e.g., Aldyl-A) still exist in some segments of natural gas delivery infrastructure and may not be ideal for transporting H_2 and RNG (Kevin L. Simmons et al. 2022). In the interim, modern pipeline materials (e.g., post-1970, low strength steel, polyethylene) currently in service may be better suited to deliver blends of H_2, RNG and SNG (Kevin Topolski et al. 2022) (American Gas Association 2023).

For high pressure common carrier pipelines, an operator will need to assess their risk of H_2 embrittlement. Previous studies suggest that pipelines constructed from lower strength carbon steels (e.g., API 5L Grade X42) may be more suitable for H_2 transport compared to higher strength carbon steels (e.g., X70, X80) (Kevin Topolski et al. 2022). However, pipeline strength is not the only factor to consider for H_2 compatibility. There is a need to conduct comprehensive, pipeline-specific assessments to determine if a pipeline's integrity (e.g., existing damage, weld quality) and characteristics (e.g., operating pressure, wall thickness) are suitable for H_2. The goal is to ensure safety margins continue to be satisfactory when H_2 is present in the pipeline. Fitness-for-service evaluations, fatigue crack growth and fracture mechanics analyses are necessary to determine whether existing pipelines can be repurposed for H_2 service.

In addition, elastomers used in pipeline components will need to be inventoried to determine compatibility with H_2 and CO_2. For example, NBR (nitrile butadiene rubber), HNBR (hydrogenated nitrile butadiene rubber), TFEP (tetrafluoroethylene propylene), FKM (fluoroelastomer), and FFKM (perfluoroelastomer) are elastomers commonly found in natural gas systems. FKM and NBR are not recommended for CO_2 service, while previous studies suggest FFKM and HNBR may be suitable (Low Carbon Resources Initiative 2023).

Gulf Coast Pipeline Material Trends

Knowledge of remaining cast-iron and bare steel pipe locations is a critical component of scaling H_2 and RNG, SNG blends in the Gulf Coast. **Figure 41** and **Figure 42** visualize the progress of cast iron and bare steel pipeline replacements for natural gas distribution mains and services (PHMSA, Pipeline Bare Steel and Cast Iron Inventories, 2025).

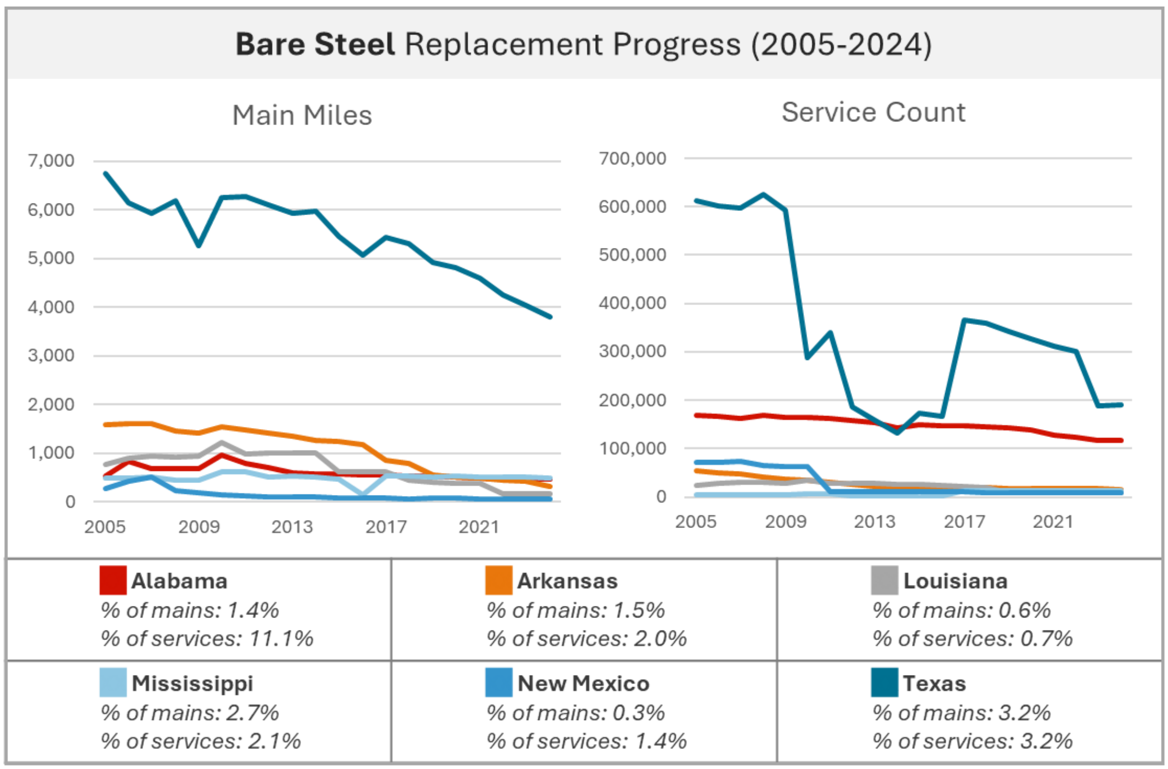


Figure 41. Remaining bare steel pipe in natural gas distribution and transmission systems

The remaining percentage of cast iron and bare steel in each state's natural gas distribution and transmission networks is expected to be a rate-limiting factor for emerging fuel blends. Alabama possesses higher percentages of bare steel and cast iron as a function of total distribution and transmission infrastructure in-state. However, the majority of remaining bare steel distribution main miles and services in the Gulf Coast can be found in Texas.

Remaining cast iron in the Gulf Coast natural gas distribution systems represent less than 2% of total distribution mains and services, a direct result of rigorous pipeline replacement programs (**Figure 42**).

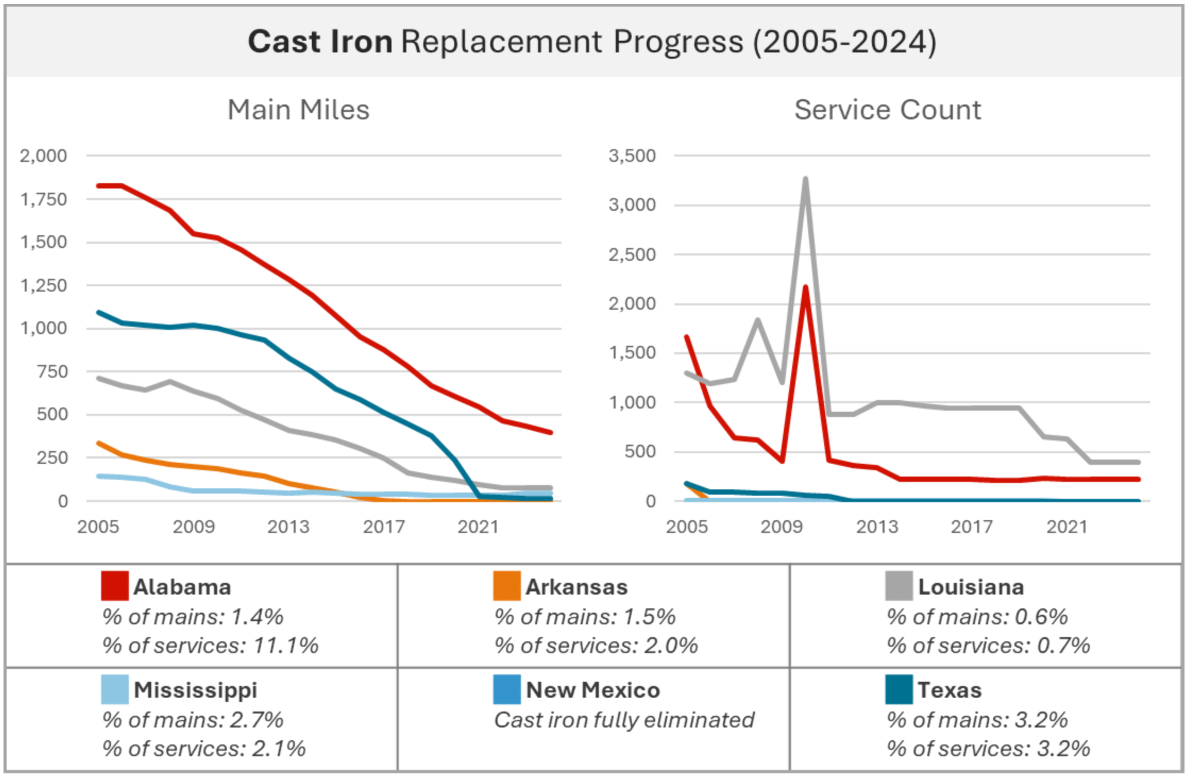


Figure 42. Remaining cast iron pipe in natural gas distribution

Similar to the bare steel pipe trends, Alabama has the highest state percentage of remaining cast iron, but trails behind Texas in the total number of cast iron main miles still in service for the entire Gulf Coast region. However, Texas and Mississippi have eliminated cast iron in natural gas services, unlike Louisiana and Alabama. The remaining cast iron service lines will need to be replaced if emerging fuel blends are introduced to end users currently served by these lines.

Post-1970s installed distribution and transmission pipe exclude cast iron and bare steel but still include some vintage plastics installed (Aldy-A pipe). The 2024 PHMSA pipeline inventories show that Gulf Coast states generally have similar percentages of distribution mains installed before the 1970s (ranging from 23.9% to 31.8%), with exceptions of Mississippi (41.2%) and Louisiana (50.2%) (PHMSA, Pipeline Bare Steel and Cast Iron Inventories, 2025).

Pipeline System Capacity

While RNG and SNG have higher heating values comparable to fossil-based natural gas, H_2 has approximately one-third the higher heating value of natural gas. As a result, approximately three times the volume of H_2 would be needed to deliver the same amount of energy. In addition, due to differences in mass density (i.e., H_2 is approximately nine times less dense than natural gas), a H_2 pipeline of the same diameter operating under the same pressure can typically only deliver 80 to 98% of the energy content that a natural gas pipeline can (IRENA 2022). Given that some parts of the Gulf Coast pipeline system are operating at or near capacity, an operator considering introducing H_2 into their system will need to conduct hydraulic analyses and system assessments to determine if their pipelines can accommodate increased gas volumes to maintain energy throughput. Pipeline extensions, pipeline upgrades, and/or compressor station modifications, may be needed to allow for increased throughput.

Midstream Equipment Compatibility

Due to its lower density and molecular weight, H_2 requires about three times more compression energy than natural gas to achieve the same pressures and flow rates (Energy.Gov, n.d.). Consequently, existing compressors may need to be replaced with larger units to meet the increased compression load.

The compatibility of compressor materials with H_2 will also need to be evaluated. H_2's small molecular size may lead to increased leakage through existing seals, gaskets, and valves designed for natural gas use. Therefore, an inventory of the materials and components installed should be conducted to confirm suitability for H_2. Another consideration to be made is potential changes to compressor performance (e.g., efficiency, temperature, pressure) due to the presence of H_2. There may be a need for modifications to system controls modifications and maintenance activities and intervals.

CO_2 Pipeline-Specific Challenges

Two key technical considerations need to be made when considering repurposing existing pipelines for CO_2 service: operating pressure requirements and corrosion risk (U.S. DOE Fossil Energy and Carbon Management 2022). It is most economical to transport CO_2 as a supercritical fluid (i.e., above 1,057 psi and 88ºF (Netl.Doe.Gov, n.d.)) as it requires less storage volume. However, most natural gas pipelines were not designed to be operated at such high pressures. In addition, impurities (e.g., water, oxygen, hydrogen sulfide) from various CO_2 sources can increase the risk of internal corrosion. Operators would need to perform comprehensive, pipeline-specific assessments to evaluate if existing pipelines are suitable for CO_2 service. Potential mitigative measures could be internal coatings, corrosion inhibitors, and/or enhanced CO_2 dehydration.

Importance of Production Facility Locality to End Use

In the short term, pipeline transport of H_2, RNG, SNG, and CO_2 is more effectively achievable at relatively short distances between production facilities and end users. An operator would need to account for fewer pipeline material differences and end use sensitivities, which simplify interconnection logistics. For example, RNG production facilities are often in rural areas and positioned near end-users rather than midstream natural gas networks.

However, one key challenge that must be addressed is the geographic alignment between biomass availability and the location of end users. RNG and SNG production is heavily dependent on access to sustainable feedstocks. These resources are typically concentrated in rural areas, which may be far from major industrial centers or urban energy consumers. As a result, the feasibility of short-distance pipeline transport relies not only on technical compatibility but also on the spatial distribution of feedstocks relative to demand centers.

For example, in regions where biomass is abundant but end-use demand is limited, producers may face logistical and economic barriers in transporting RNG to market. Conversely, in areas with high demand for low-carbon fuels but limited local biomass, alternative supply chain strategies (e.g., centralized upgrade facilities, multimodal transport) may be required.

In addition, depending on the locations of interconnections, more complex analyses of end users who will directly accept RNG, SNG, CO_2, and H_2 may be necessary. H_2 separation technologies can be an option to strictly control H_2 content delivered to end users. In contrast, SNG and RNG blends are more effectively controlled at the point of interconnection. In cases where industrial end users have strict gas quality requirements, there may be a need to limit the H_2, RNG, or SNG blending ratios or to install additional gas conditioning equipment to ensure end-use compatibility.

Emerging Fuels Suitability for Natural Gas End-Users

Desirable blend rates of H_2, RNG, and SNG delivered will depend on the end uses. Pure H_2 is already utilized for chemical and transportation end-uses. However, some end-use equipment can be sensitive to H_2 in the feed gas and would need to be retrofitted, replaced, or provided alternative gas supplies that do not contain elevated amounts of H_2.

The locations of different end-use sectors are a critical consideration for scaling different H_2 blends. **Figure 43** visualizes natural gas consumption in the Gulf Coast region for residential, commercial, and industrial sectors.

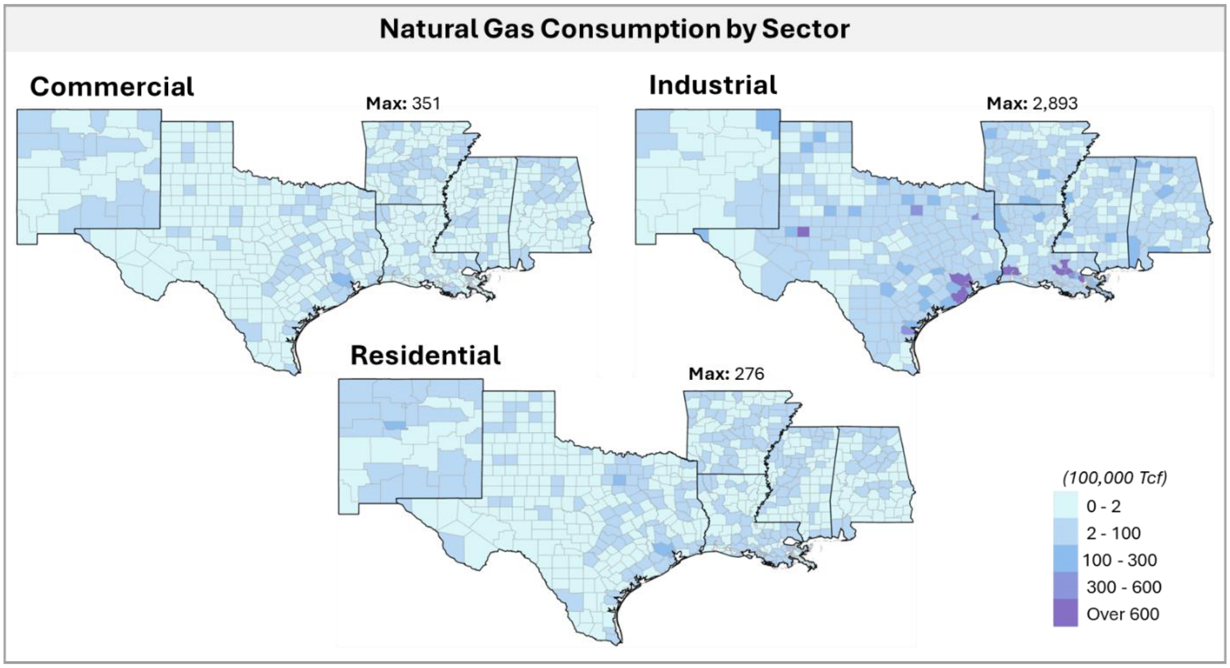


Figure 43. Gulf Coast natural gas consumption by sector (NETL, 2024)

Commercial and residential natural gas consumption in the Gulf Coast closely align in most counties in the region and are anticipated to be early adopters of higher H_2 blends. Residential end use equipment research studies have identified that most residential combustion equipment are suitable for up to 20 vol% H_2 blends, but some appliances would require retrofits when adopting higher blends.

Industrial end users of natural gas in the Gulf Coast are significantly dispersed across the region but are especially concentrated along the shared coastlines of Texas and Louisiana. With the highly heterogeneous end uses across the region, H_2 deblending stations can be strategically placed where significantly different end use H_2 specifications are needed.

RNG/SNG Suitability

Although RNG and SNG are chemically similar to fossil-based natural gas, some pathways require pretreatment to remove trace constituents (e.g., siloxanes, volatile organic compounds (VOCs), ammonia, hydrogen sulfide, oxygen) that could affect compatibility with specific natural gas end-uses. In higher quantities, these constituents can lead to corrosion and deposit formation, which impacts appliance performance and integrity. Given these potential impacts, it is critical to have adequate gas conditioning and monitoring in place to ensure that the RNG and SNG meets gas quality requirements prior to injection into the pipeline system. Current RNG interconnections with natural gas networks employ sensitive gas analyzer systems to consistently monitor gas quality, as well as limit blending rates with respect to end user applications. Additionally, the Northeast Gas Association and GTI Energy have published a technical framework that provides guidance necessary for the introduction of RNG into the natural gas distribution pipeline network (Northeast Gas Association, GTI Energy, n.d.).

H_2 Suitability

Factoring equipment sensitivities will be essential to expand H_2 blends for natural gas consumers. Certain end-users (e.g., CNG filling stations, LNG peak shaving plants, and steel and glass manufacturers) have strict gas quality requirements and may face significant operational challenges with H_2 (C.J. Suchovsky et al. 2021). Example concerns are partial liquefaction[5], malfunction or degradation of burners, reduced heat transfer, and increased moisture content or NOx emissions.

Table 4 provides a high-level summary of typical H_2 limits of various end-use equipment based on literature and previous testing.

Table 4. Summary of typical H_2 limits of select end uses

End-Use Sector	Example(s)	Typical H_2 Blend Limit (vol%)	Key Considerations
Residential & Commercial	Furnaces, water heaters, boilers, stoves	15 to 30 (C.J. Suchovsky et al. 2021) (Glanville et al. 2022)	NOx emissions, ignition, flashback

[5] H_2 liquefies at -432.4°F versus natural gas which typically liquefies at -259.6°F.

Gas Turbines	Power generation turbines	5 to 10 (U.S. Environmental Protection Agency 2023)	Flashback, NOx emissions
Internal Combustion Engines	Natural gas vehicles, generator set	10 (ASTM International 2024)	Ignition timing, emissions, engine knock
Industrial – LNG and Chemicals Manufacturing	Liquefier	0.1 (American Gas Association 2013)	Partial liquefaction, reforming chemistry
Industrial Combustion	Kilns, process heaters	10 (Pipeline Research Council International 2020)	Burner damage, flame temperature, moisture content

These concerns can pose risks to equipment and process safety. Therefore, as a first step, natural gas operators considering introducing H_2 into their systems should review their customer database to identify users with equipment that may be sensitive to changes in gas quality. Once these sensitive end-users have been identified, the operator should request an inventory of their equipment. Non-invasive means of surveying the equipment population could be implemented (e.g., environmental permits, industry databases), and mitigative measures can be recommended to permit continued operation as a function of H_2 in the gas supply (e.g., burner modifications, engine catalyst replacements, air-fuel ratio controller upgrades, H_2 removal technology installations).

H_2 separation technologies have the potential to protect these sensitive end-users. These technologies can selectively remove H_2 from a H_2-natural gas blend, allowing gas utilities to deliver H_2 blends to most end-users while still providing near H_2-free gas to sensitive end-users with strict gas quality requirements. In addition, these technologies can support H_2 delivery systems for end-use applications such as H_2 refueling stations or fuel cells. This dual approach has the potential to enhance the flexibility and resiliency of future energy systems.

Previous testing suggests that residential appliances can generally accept up to 20 vol% H_2. However, higher blends may cause flashback, incomplete combustion, material embrittlement and cracking, and safety issues (Brania, 2024). Existing gas appliances would need to be retrofitted or replaced with versions suitable for higher H_2 blends.

There is still a need to further develop retrofit technology solutions for the use of H_2 in natural gas-designed residential appliances. While there has been some development of H_2-specific appliances (such as boilers and water heaters), most appliances are still in development and not yet widely available on the market. One example is the Viessmann fuel cell boiler, Vitovalor PT2, which has been developed for use in detached houses to provide both heat and power (Viessmann, 2025). In the nearer term, operators may consider delivering low H_2 blends, RNG, or SNG to residential customers as transitional solutions.

Based on the type of end-users within a service territory and their respective gas quality sensitivities, natural gas operators can strategically plan the distribution of H_2 blends to optimize system performance and safety. Areas with a higher concentration of end-users that are more tolerant to H_2 could be prioritized to receive higher H_2 blend concentrations, and areas with sensitive end-users can be supplied with lower H_2 blends, provided H_2 separation technologies, or served with RNG or SNG. This targeted deployment approach would allow natural gas operators to optimize the use of H_2 across the system to enhance overall energy system reliability while preserving end-use safety.

Geographical Optimization Recommendations

Based on the Gulf Coast's current infrastructure and the CBA results, there are two general scenarios by which the Gulf Coast region can be judged, depending on how optimistic investors are with the development of H_2 technologies and how much improvement is possible with a given amount of research into H_2 production technologies.

Scenario 1: Low H_2 with No Significant Advancements

This scenario assumes that advancements to H_2 production technologies are not capable of surpassing the high economic barriers to entry within the Gulf Coast due to the prevalence of low cost natural gas and other fossil resources in the region. Continued use of natural gas as an end-use fuel can observe emissions reductions when using carbon capture and storage. Under this scenario, the following are recommended:

1. **Invest in expanding carbon capture infrastructure and the creation of carbon capture hubs.** Use of carbon capture technologies to reduce carbon emissions of fossil fuels is more cost effective compared to decarbonizing production of H_2 or other emerging fuels, with levelized costs ranging $40 – 120/tonne for point source capture, and $130–340/tonne for direct air capture. Note that these costs are for dilute sources of CO_2 (e.g., power plants). Capture from more concentrated sources of CO_2, such as certain industrial processes, can cost as low as $15/tonne (Baylin-Stern & Berghout, 2021). These costs are significantly lower than any of the emerging fuel pathways presented in this report.
2. **Expand existing CO_2 pipeline infrastructure within the region.** Of prime importance is connecting the western pipeline cluster in Texas and New Mexico with the eastern cluster in Louisiana and Mississippi. Additional pipelines should be constructed with endpoints in Central Arkansas near Little Rock, southern Louisiana in New Orleans and Baton Rouge, southwestern and central Louisiana near Lake Charles and Alexandria, and western Alabama between Mobile and Birmingham. These new pipelines will connect the various industrial centers together more fluidly and enable long-distance transport of captured industrial CO_2 to suitable storage sites as well as to existing carbon conversion sites to produce chemicals such as methanol.

Scenario 2: Optimistic H_2 Improvements and High Investment Support

This scenario assumes that H_2 technologies reach a point where the production costs (specifically for the gasification method) will either reach price-parity with natural gas, or where the required incentives are comparable to those needed for carbon capture technologies in the region. Based on these assumptions, the following are recommended:

1. **Support research on optimized H_2-based thermal and bio-gasification technologies.** Fostering engagement between industry, academia, and government to improve these technologies will be essential.
2. **Conduct system-specific assessments to determine H_2 and CO_2 compatibility of existing pipelines** as pipeline delivery is more cost-effective and scalable than trucking. Pipelines can provide high-volume transport, reduce transport emissions, and enhance end user accessibility. If the results of these studies conclude that

existing pipelines are not suitable for H_2 or CO_2 transport, state- or federal-level support should be leveraged to retrofit or replace pipelines. Wherever possible, the new or upgraded pipelines should utilize existing natural gas pipeline rights-of-way to reduce land acquisition and site preparation costs, and to expedite permitting timelines.

3. **Expand renewable energy infrastructure in the region** to reduce total energy demand to support the adoption of H_2. These new renewable plants will also enable further opportunities for electrolysis-based H_2. While electrolysis is the least cost-effective production pathway, it is useful for improving renewable CFs during off-peak hours through energy storage via H_2. Excess H_2 from these new plants can be sold on the market to recoup costs. Louisiana and Mississippi currently have the lowest renewables penetration in the region. From the data gathered, Northwest Louisiana near Shreveport has high geothermal potential along with northwest Texas and a small section of west-central Mississippi (Class 2). A few plants in this area coupled with electrolysis could help with decarbonization efforts in these areas. In addition, there are a number of rivers in west-central and northern Louisiana (e.g., Vernon, Allen, and Beauregard Parishes in the west and Union Parish in the north) and throughout most of Mississippi that may be suitable for more hydroelectric plants. These rivers should be assessed for opportunities to construct new hydroelectric plants in these states to support decarbonization efforts.

Aside from the above scenarios, expanding support for RNG technologies (especially in the Arkansas Delta) is recommended. The CBA results demonstrated that RNG, particularly biodigester-based RNG, is the most promising emerging fuel technology in the region. Arkansas is a prime location for this type of technology due to the extremely high natural gas prices (>$9/MMBtu) in some areas. The Arkansas Delta is uniquely positioned to be a suitable start for RNG plants due to the large quantity of available biomass.

Cost Comparison of New, Retrofitted, and Decommissioning Pipelines

Current estimates show that new H_2 pipelines cost about 2-5% more than natural gas pipelines. However, because H_2 has a lower energy density than natural gas, the cost increase could be as much as 16% more for the same amount of energy delivered (EPRI, 2024). These estimates do not account for capital and operating costs for compressor stations, which can be significant given that H_2 requires approximately three times the compression power as natural gas. According to EIA's Natural Gas Pipeline Projects tracker, between 1996 and 2024, new natural gas pipeline projects in the Gulf Coast region ranged from $821,500 to $21.7 million per mile (U.S. Energy Information Administration 2025).[6] For comparison, it is estimated (using RSMeans Data Online) that a 37.5-mile 12" natural gas pipeline would cost approximately $3.4 million per mile, $3.3 million per mile, and $3.5 million per mile, in Texas, Arkansas, and Louisiana, respectively.[7] These order-of-magnitude estimates align with the EIA data. Applying the upper end of the EPRI estimate to the EIA range, a new H_2 pipeline in the Gulf Coast could potentially cost between $953,000 and $25.2 million per mile.

One key benefit of repurposing existing pipelines is the potential for substantial cost savings. It is estimated that the cost to repurpose natural gas pipelines for H_2 service is 10 to 35% of the cost of new pipeline construction (ACER 2021). The actual costs will depend on factors such as pipeline diameter, location, material type, and condition of the pipeline. Applying the upper end of this estimate and the above cost range, the cost to repurpose a pipeline in the Gulf Coast may potentially cost between $334,000 and $8.8 million per mile. In contrast, data from EIA's Natural Gas Pipeline Projects tracker indicate that the cost to decommission a pipeline can cost $6.5 million per mile[8].

When comparing new construction, retrofit, and decommissioning options, the financial case for repurposing existing infrastructure is evident. Repurposing infrastructure provides the opportunity to avoid right-of-way acquisition logistics and reduce construction emissions. Two notable examples of repurposing pipelines for H_2 service in the Gulf Coast is Air Liquide. The operator successfully repurposed two pipelines in Corpus Christi and between Freeport and Texas City. Originally designed for crude oil transport, these pipelines were converted for H_2 service through a process that included in-line inspection, cleaning, and hydrotesting (Jim Campbell 2005).

If RNG becomes the primary decarbonization pathway for the Gulf Coast region, no significant design modifications will be needed as it is chemically indistinguishable from fossil-based natural gas. However, operators will need to ensure that the RNG meets gas

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[6] This range was based on historical costs for projects that covered the Gulf Coast states defined in this study: Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas.

[7] Estimates include materials, engineering, labor, cathodic protection, permits, and land acquisition. Compression costs are excluded. State capital cities were used as representative locations. A 25% contingency has been applied.

[8] This estimate is based on a pipeline abandonment project spanning from Pennsylvania to New York.

quality requirements prior to injection into the gas system as contaminants (e.g., siloxanes, VOCs, hydrogen sulfide) can lead to pipeline integrity and end-use equipment issues as discussed in the **Emerging Fuels Suitability for Natural Gas End-Users** section.

Policy and Regulatory Landscape

Federal Oversight & Fuel Considerations

Natural gas pipeline infrastructure regulation has a long history with designated federal agencies and a well-defined framework to ensure effective and safe operation. The Pipeline and Hazardous Materials Safety Administration (PHMSA) ensures safe and reliable operation of gas pipelines and storage by establishing minimum safety requirements and operational standards. Maintaining the country's pipeline system includes monitoring the replacement of aging pipeline materials known to leak or pose system integrity risks.

Current federal policies are designed to support replacement at a consistent rate to ensure all states make continual progress towards complete elimination instead of prescribing specific replacement rates or completion timeframes.

Table 5. Summary of natural gas infrastructure regulations by agency**5** summarizes the agencies which preside over natural gas infrastructure and their roles. The Federal Energy Regulatory Commission (FERC) is responsible for approving interstate pipeline and storage facility sitting, construction, and operation in addition to regulating the wholesale sale of natural gas (Interstate Natural Gas Association of America, n.d.). Operators of interstate gas pipelines are required to submit tariffs to FERC for approval, which details operating conditions and gas quality specification including heat content, contaminants and inert gas, and operating pressure. Additional information on the regulatory frameworks and opportunities for RNG/SNG and H_2 pipelines are available in RAISE's first white paper (Reliable Affordable Infrastructure for Secure Energy 2023).

UGS facilities are regulated by the same authorities as natural gas pipeline infrastructure, and must comply with regulations, codes, and standards set by FERC, PHMSA, and the Environmental Protection Agency (EPA). FERC oversees underground natural gas storage facilities owned by interstate pipeline companies or independent operators engaged in interstate commerce, focusing solely on project access and tariff design, not facility design, operation, or maintenance. For safety regulation of underground storage facilities, however, the jurisdiction is not clear. Generally, the responsibility for facility design, safety, operation, and maintenance lies with PHMSA under the PIPES Act of 2016.

Table 5. Summary of natural gas infrastructure regulations by agency

Natural Gas Infrastructure Regulation		
Agency	**Pipelines**	**Underground Gas Storage**
PHMSA	Established national pipeline safety policy and enforces safety standards. Sets requirements for design, material selection, construction, testing, operation, inspection and maintenance of interstate pipelines.	Sets requirements for construction, maintenance, risk management, and integrity management for two categories of underground natural gas storage facilities.
FERC	Reviews proposals and grants certificates for interstate pipelines and sets conditions for pipeline construction, including sitting. Sets maximum rates for interstate pipeline transportation services.	Oversees facilities owned by interstate pipeline companies or independent operators engaged in interstate commerce, focusing solely on project access and tariff design.
EPA	Regulated equipment and activities for design, construction, operation, and maintenance of interstate pipelines. Requires monitoring and reporting of emissions under subpart W.	Sets minimum federal requirements for the Underground Injection Control program to protect public health by preventing injection wells from contaminating underground sources of drinking water.

Emerging Fuels

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. Under this regulatory framework and pursuant to FERC approval, operators may revise and include provisions in their tariff that allow for the injection and transportation of these gases, which are subject to the same gas quality standards and interchangeability specifications as conventional natural gas.

The regulation of H_2 in the H_2 blend cases poses unique challenges, both when building out a H_2-specific pipeline system and converting natural gas pipes for H_2 blending. The current regulatory framework includes no dedicated federal authority designated to approve interstate H_2 pipelines, meaning developers of H_2 -specific pipelines must get approval from all the state authorities through which their proposed H_2 pipe would enter. While this process has been adequate for building the current H_2 system, it may be prudent to institute federal regulations and standardized processes for interstate H_2 pipeline sitting and permitting as larger H_2 systems are developed.

Under the current regulatory framework, FERC has authority over the rates of interstate natural gas pipelines and the Surface Transportation Board (STB) regulates H_2-specific pipelines as common carriers, reflecting H_2's traditional use as an industrial feedstock and not an energy carrier or fuel source. 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 H_2 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 H_2 blended pipelines, the appropriate classification of H_2 remains unclear and leads to some jurisdictional uncertainty for future use-cases. If H_2 is classified as a natural gas, FERC would maintain jurisdiction over natural gas and H_2-specific pipelines in the case of increasing concentrations of H_2 blending. However, if H_2 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 H_2 (Diamond 2022). 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 H_2 blends by including provisions in their FERC-approved tariffs prescribing the concentration of H_2 they wish to blend (U.S. Congress 2021).

Additional clarification on these matters may be needed as the number of H_2-specific and H_2 blended pipelines increases, as well as clear federal standards for blended gas quality and interchangeability necessary for implementing a successful H_2-blending strategy. A significant gap in safety and operational standards for H_2 blends may also challenge the blending of H_2 at scale. As an extremely flammable gas, blended H_2 introduces new risks for explosion that aren't currently accounted for by PHMSA safety regulations. Because H_2 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 H_2 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 (*U.S. National Clean Hydrogen Strategy and Roadmap*, n.d.).

Table 6. Summary of agency jurisdiction of infrastructure

Agency Jurisdiction of Infrastructure				
Fuel	**Infrastructure Safety**	**Interstate Commerce**	**Approval/ Certification**	**Emissions**
NG	PHMSA	FERC	FERC	EPA
RNG/SNG	PHMSA	FERC	FERC	EPA
H_2	PHMSA	None	States	EPA
CO_2	PHMSA	State (pipelines)	State (pipelines) EPA (UGS & wells)	EPA

Gulf Coast Landscape

A comprehensive review of the current policy and regulatory landscape in the Gulf Coast was performed to support the analyses of decarbonization pathways and aid in the identification of regional opportunities. This review includes state-level policies, regulations, standards, codes, and incentives pertaining to natural gas infrastructure and industry, the production and transportation of emerging fuels, and resilience and modernization of the region's energy system. The primary takeaways from this review include the following:

- The Gulf Coast region is positioning natural gas as a key power source for the future.
- There are opportunities to further expand state level policies to promote emissions reduction from existing infrastructure.
- Several states in the Gulf Coast have successfully passed legislation supporting deep decarbonization, workforce training and development, and infrastructure resilience.

Natural Gas Infrastructure & Industry

Reducing emissions from current natural gas infrastructure is vital to achieving the nationwide decarbonization goals. Therefore, requirements for routine leak surveys and the replacement of leak-prone pipeline materials such as cast iron and bare steel are examined in depth, as these activities can greatly reduce carbon emissions from existing natural gas infrastructure. States within the Gulf Coast generally enforce the federal regulations instead of implementing state specific leak survey and repair requirements. The only exception in the region is Texas, which requires operators to base their leak survey programs on a risk model that prioritizes leak segments posing the greatest hazard. Because federal regulations reflect the minimum level achievable by all states, there are opportunities for states to further reduce carbon emissions and enhance safety based on individual capabilities and priorities. Other regions like the East Coast have enacted additional regulations beyond what is federally required, with states like New York implementing stringent performance standards for leak detection equipment and prescriptive repair schedules for all leak types including those deemed non-hazardous.

There are few notable state-specific policies or regulations related to the replacement of cast iron and bare steel pipes, though Arkansas and New Mexico have eliminated cast iron from their systems. Texas passed legislation requiring the removal of cast iron from natural gas systems by 2021; however, cast iron was still reported to PHMSA in 2022 according to the federal Cast and Wrought Iron Inventory. There is an opportunity to accelerate the replacement of aging infrastructure in the region by establishing state-level pipeline replacement program requirements and infrastructure specific cost-recovery mechanisms. Kansas, for example, has an Accelerated Replacement Program that includes cost-recovery mechanisms for utilities replacing leak prone pipes in the best interest of public safety and service reliability. Replacement activities may begin to accelerate in the Gulf Coast as funding from the Natural Gas Distribution Infrastructure Safety and Modernization grant program is distributed in New Mexico and Alabama.

Gulf Coast states are positioning natural gas as a key energy source for the future by enacting preemptive gas laws and supporting natural gas production. Texas has enacted numerous policies supporting future natural gas use by limiting federal legislation that seeks to restrict oil and gas production, and by encouraging dispatchable energy production. Alabama has also passed legislation supporting the future use of natural gas and urged federal legislators to expand offshore oil and natural gas leasing programs past 2024. New Mexico is the outlier of the region, having passed legislation that requires natural gas utilities to pursue all cost-effective energy efficiency and demand-side management measures in addition to reducing/limiting annual volumes of flared and vented natural gas.

Emerging Fuels Production and Transportation

Incentives and regulatory frameworks for the production and transportation of RNG and H_2 via pipeline are examined as these low-carbon fuels are likely to play a role in decarbonization and require additional regulatory support to be implemented at scale.

CCUS also falls into this category because of its potential to further reduce carbon emissions from low-carbon fuel supply chains.

The production of RNG is incentivized throughout the Gulf Coast, including through production and tax credits. Texas gives producers 20 cents for each MMBtu of RNG produced for the first 10 years of the plant's life. Similarly, New Mexico and Alabama encourage production facilities to process biomass feedstocks into biofuels and convert waste into biogas in the form of tax credits. Louisiana has encouraged RNG by considering the production of biogas from either forest products or agricultural harvesting to be renewable and carbon neutral, or even carbon negative when paired with carbon capture and storage. However, many of these policies only apply to biofuels intended for use as vehicle and aviation fuel, resulting in an opportunity to incentivize the production of RNG specifically for injection into the natural gas system.

There is notable legislative activity related to H_2 production and transportation as an energy source in preparation for the upcoming regional H_2 hub. The proposed HyVelocity Hub will receive up to $1.2 billion in Bipartisan Infrastructure Law funding and expand upon 1,000 miles of existing H_2 pipelines and production plants. H_2 hub developers recently requested the U.S. Treasury Department to make the 45V H_2 production tax credit more robust and flexible to facilitate economic viability for low carbon H_2 and allow the industry to grow. The 45V tax credit utilizes GREET modelling to estimate lifecycle GHG emissions and rewards projects with lower GHG intensities. States including New Mexico and Texas are supporting H_2 production and infrastructure development at the state-level through production tax credits and grant programs. Texas' Railroad Commission recently approved the development of 12 salt caverns by NeuVenturs, LLC, which will add 96 Bcf of additional storage capacity for natural gas and 100,000 metric tons of capacity for H_2 (Pipeline & Gas Journal 2025). Alternatively, Louisiana is supporting H_2 use by preventing local governments from limiting consumer access to any alternative transportation fuels.

State primacy of Class VI wells is vital to CCUS adoption, which allows states to grant permits for the construction and operation of underground carbon sequestration sites otherwise granted by the EPA. The EPA's review of permits and primacy applications moves slowly, resulting in states like Texas waiting years to hear a decision. Louisiana is currently the only state in the Gulf Coast with Class VI primacy. A lack of federal CO_2

pipeline safety standards is another significant hurdle for developing CCUS technologies in the Gulf Coast, especially after the 2020 CO_2 pipeline rupture in Satartia, Mississippi. States are reluctant to develop additional CO_2 pipeline infrastructure under current safety regulations when the Satartia community is still experiencing and recovering from the impacts three years later.

The 45Q Tax Credit for Carbon Sequestration may help spur more development, with different credits applying to the manner of carbon capture and whether it is utilized for enhanced oil recovery afterwards. The delay in application review poses a significant hurdle to state regulation of CCUS and will need to be addressed by the EPA to facilitate development of these projects. Nevertheless, Gulf Coast states are preparing for CCUS development by establishing long-term storage monitoring programs, trust funds, and stewardship requirements. Arkansas is encouraging the adoption of carbon capture technologies by deeming certain biofuels carbon negative when coupled with CCUS. Arkansas took additional steps to support carbon capture by enacting Act 149 on February 25, 2025, which provides clarification on the regulation of CCUS projects and establishes a carbon dioxide storage fund (An Act to Amend the Law Concerning the Oil and Gas Commission; to Clarify the Regulation of Carbon Capture and Sequestration; to Establish the Carbon Dioxide Storage Fund; and for Other Purposes 2025).

Energy System Resilience & Modernization

System reliability and weatherization are important pillars of a resilient energy system, and legislation related to energy system planning and emissions mitigation are tracked as key components regardless of the energy source.

Several states in the Gulf Coast have set executive emissions reduction targets, established dedicated climate task forces, or published climate action plans (CAP). The three climate action plans in the region include strategies and recommendations for transitioning to low-carbon fuels and reaching state emissions reduction goals. Louisiana's CAP notably tasks agencies with developing regulatory requirements for electrifying the industrial sector by 2050. Similar climate-related legislation and plans have been unsuccessful in Texas to date.

Most of the grid reliability and infrastructure weatherization policies in the Gulf Coast originate from Texas after severe winter storms in 2021 caused grid failure. In addition to including extreme weather events planning in mandatory utility Emergency Operations Plans, Texas enacted additional Weather Emergency Preparedness Standards for natural gas facilities and provides funding for weatherizing transmission and distribution infrastructure. Texas is also improving energy system reliability by increasing the state's dispatchable power generation and incentivizing facilities that can produce power at times of high demand. Outside of Texas, Arkansas passed the Electric Utility and Gas Utility Storm Recovery Securitization Act in 2021 to provide financing for approved utilities for storm recovery costs to mitigate the impact to consumers.

The One Big Beautiful Bill

On July 4, 2025, the One Big Beautiful Bill (OBBB) was signed into law, changing the US energy policy landscape with strong implications for the Gulf Coast natural gas industry (One Big Beautiful Bill Act 2025). The legislation is expected to influence the sector by expanding access to offshore resources, accelerating infrastructure development, and enhancing the economic competitiveness of natural gas operations in the region.

OBBB mandated the expansion of offshore drilling, requiring a minimum of two offshore lease sales per year in the Gulf of Mexico through 2039, opening new areas for exploration and production. This will directly affect Louisiana, Texas, Mississippi, and Alabama, which have existing offshore gas infrastructure and port access. Increased leasing can lead to more natural gas exploration and development and is expected to increase gas production capacity.

The bill also introduces major reforms to infrastructure permitting. By streamlining the environmental review process under the National Environmental Policy Act (NEPA), it allows developers to pay for expedited reviews, significantly cutting down the approval time for pipelines, LNG terminals, and related energy infrastructure. This is especially important for the Gulf Coast region, where a large share of the nation's gas pipelines and LNG export terminals are located. The result will be faster construction of key facilities, increased export volumes, and greater resilience in natural gas supply chains across the Gulf region.

Financial measures included in the OBBB further strengthen the industry's position. The legislation reinstates full deductions for intangible drilling costs, reversing limitations imposed by prior regulations. This provision lowers operational expenses and improves the financial outlook for producers.

The expanded leasing opportunities, streamlined permitting processes, and fiscal incentives have the potential to catalyze growth in the Gulf Coast's natural gas sector. However, given the bill's recent passage, its long-term implications have not yet been incorporated into the optimization modeling exercises presented in earlier chapters of this report. Further analysis will be needed to fully assess the potential impacts of the OBBB on regional and national energy trends over time.

Discussion

This section discusses the key insights from the case study, highlighting the considerations, potential opportunities, and strategic recommendations for deploying emerging fuels in Gulf Coast natural gas infrastructure.

Existing Infrastructure Utilization

Repurposing infrastructure offers a potential cost-effective and practical pathway to support widespread adoption of emerging fuels. Given the Gulf Coast's extensive pipeline network, repurposing existing pipelines can reduce capital costs and lower construction-related emissions. Additionally, repurposing existing assets and rights-of-way has the potential to accelerate emerging fuels deployment as permitting and environmental review times may be shorter. While repurposing offers compelling potential benefits, there are several key technical and economic aspects to consider.

Technical

Since RNG and SNG are chemically similar to fossil-based natural gas, no significant modifications and assessments are needed for integration with existing infrastructure. However, operators will need to closely monitor for trace constituents (e.g., siloxanes, VOCs) that may be present depending on the feedstock and production process. These constituents can impact the integrity of pipelines and end-use equipment. To ensure safe and reliable integration into existing gas infrastructure, it is critical to ensure RNG and SNG meet gas quality requirements prior to injection into the pipeline system. Gas conditioning and continuous gas composition monitoring are quality assurance measures that will help protect the pipeline system and end-users.

In contrast to RNG and SNG, H_2 integration will require a number of considerations. One key consideration is the material compatibility of pipelines and components. Previous studies suggest that lower strength carbon steels and modern polyethylene pipelines are generally suitable for H_2 service. However, the existing condition of the pipelines is an important factor (i.e., H_2 can exacerbate existing damage). Therefore, operators will need to conduct thorough integrity assessments to determine whether their current pipelines are fit for H_2 service.

Due to its lower density, H_2 requires approximately three times more compression power as natural gas. Even when transporting H_2 blends, there may be a need to upgrade or replace existing compressor stations. Operators should conduct an inventory of their compressors and collaborate with manufacturers to assess if any modifications to parts and controls are needed to accommodate H_2. Proactive coordination will mitigate operational issues and maintain system reliability.

H_2 has approximately one-third the volumetric energy content of natural gas. As a result, a H_2-natural gas blend will have a lower higher heating value compared to typical natural gas. A greater volume of gas is needed to continue delivering the same amount of energy to end-users. This difference in energy content has important implications for system capacity. Given that parts of the Gulf Coast pipeline system operate at or near capacity during peak times, the existing system may not be able to sustain the increased gas volumes needed. Operators will need to conduct comprehensive system planning assessments to determine which parts of their system can accommodate increased gas volumes and where upgrades may be necessary.

Certain end-users (e.g., chemicals, metals, glass manufacturing) have strict gas quality requirements and may be unable to accept high H_2 blends. If system-wide blending is implemented, operators will need to develop mitigative measures for these end-users. Potential solutions include installing H_2 separation technologies at delivery points to reduce H_2 content of the gas supply or providing dedicated alternative gas supplies (e.g., RNG or SNG). Early engagement with these end-users is key to aligning energy transition plans with the industrial sector's needs.

Economic

It is estimated that repurposing natural gas pipelines for H_2 service is 10 to 35% of the cost of new pipeline construction (ACER 2021). However, the actual costs can vary significantly depending on the diameter, location, material type, and condition of the pipeline. Operators will also need to account for costs associated with fitness-for-service assessments, enhanced gas quality monitoring, and potential upgrades or replacements of compressors and other critical components when evaluating infrastructure for repurposing.

As discussed in the previous section, H_2 blends will require a greater volume of gas to be delivered to maintain the same energy delivery to end-users. This operational shift will require operators to source and transport greater volumes of gas, which will lead to increased procurement and compression costs. Operators will need to consider these logistics with their system planning.

Maintenance costs are another important consideration as integrity management programs will likely be updated due to the presence of H_2. There may be a need for more frequent pipeline inspections and/or leak surveys. The frequency of inspections will depend on the location and condition of the pipeline (e.g., operating pressure, existing damage, wall thickness, tensile strength). For RNG and SNG, robust gas quality monitoring at interconnection points will be crucial to ensure pipeline and end-use compatibility. These additional operating and maintenance requirements represent important cost considerations that need to be factored as operators plan to integrate H_2, RNG, and/or SNG into their systems.

Although the TEA results of this case study indicate that methane pyrolysis/gasification and MSW-RNG are the most promising emerging fuel pathways, both options are currently more expensive than conventional natural gas. Therefore, operators will need to evaluate the financial implications of adopting these higher-cost fuels. To offset costs, operators could explore long-term procurement contracts, potential regulatory incentives and subsidies, or low-carbon fuel standard credits.

Potential Impact of Assumptions on Results

The analyses consider several economic scenarios to better understand market conditions which can have supportive, unsupportive and relatively neutral impacts to the scaling of H_2, RNG, and SNG in the Gulf Coast region.

Regarding the base case and other BAUs, NEMS has a number of assumptions around macroeconomic drivers, financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics. Clearly, many deviations from model assumptions have an opportunity to change the actual outcome from base case for emerging pathway assumptions. These BAUs have been updated to current status as much as possible by including the OL-NEMS to bring the AEO23 two more current assumptions. This model includes updated technology costs for technologies already represented (e.g., SMR). Existing data is added for technologies that are underrepresented in AEO23 to give a full suite of options to the BAU according to the needs of this study (e.g., plasma pyrolysis).

An example of a shift that could impact the applicability of BAU scenarios would be new policies pushing the energy industry toward fewer renewable options and more fossil fuels. The recent passing of The One Big Beautiful Bill (OBBB) is an example of this sort of shift. This shift is represented by BAU #4, which forces the model to consider a similar shift but for different reasons (i.e., less research into renewable fuels). If another type of policy or economic shift pushes the baseline into the regime not covered by the BAUs, the emerging pathways could not be compared to an applicable BAU.

Regarding resource availability, consider a scenario where resources are not available as much as promised due to competing destinations for these resources. In this type of scenario, low-carbon fuel requirements feedstocks would have lower maximum production rates. Potential pathways that could be affected by this include RNG (with dairy feedstock) and H_2 (with biomass feedstock). This type of feedstock restriction would require a blend of low-carbon fuels to achieve the desired outcome. Similarly, LFG has been assumed to be freely available due to the calculated overall capacity by the EPA LMOP, but competing uses (e.g., onsite CNG/power utilization) were not considered here. If LFG has a more restricted capacity, some of the assumed use in this study would need to be backfilled with another fuel.

From an LCA standpoint, process shifts could lead to modified LCA results that reduce carbon intensity benefits. For example, if the plasma pyrolysis reference H_2 production does not provide carbon black that qualifies as a carbon-negative co-product, this would cut its ability to give low (or negative) CI. Any such changes to this specific pathway (or others) would lead to minimizing its ability to be a viable candidate for an energy systems network.

Blue H_2 through CO_2 capture from SMR and ATR processes are not only a strong candidate for minimizing CI of H_2, but they also provide the simplest route to low-carbon fuel sources. They are a small update to brownfield or greenfield processes for high impact. However, standards for CO_2 capture are still being established. This report cites capture rates for SMR and ATR at 96% and 94%, respectively, from respected literature. Other resources suggest that these capture rates could be in the range of 80% and 91-93%, respectively. This type of change would make these pathways for H_2

production less favorable, and SMR and ATR with CCS would be less used in a total mix of H_2 production.

RNG feedstocks, like landfill gas and municipal solid waste, are assumed to be "true wastes", as proposed by GREET and other life cycle inventory databases. This is beneficial to the CI of relevant RNG pathways because the CI of these elemental feedstocks are zero. If the feedstock CI were higher or lower than zero, this type of change would make the relevant RNG pathway less or more favorable, respectively.

The feasibility of 20% RNG or SNG still needs to be thoroughly evaluated. Some challenges to these blend rates include resource availability and infrastructure compatibility.

Changing Fuel Mix

This case study's analyses consider a range of market conditions and fuel adoption scenarios possible with the current natural gas systems in the Gulf Coast region. The assumptions included herein do not consider potential market influences of fuel mix changes in the region, which can ultimately impact the feasibility of scaling H_2, RNG, and SNG. For instance, natural gas demand can be significantly impacted by electrification and fuel switching in the transportation industry. Natural gas demand is also highly dependent on economic activity, which can be influenced by a range of domestic and international factors. Current natural gas delivery capacities satisfy regional natural gas demand in the Gulf Coast. However, if major economic growth occurs in the coming decades in the Gulf Coast region, the true feasibility of scaling emerging fuels may differ from the considered BAU scenarios.

While this study has leveraged federal datasets to estimate feedstock availability, truly accessible feedstock will need to be assessed on a project scale.

Limitations of Findings and Information Gaps

The depth of LCA, TEA, and CBA summaries were limited by the complexity of inputs into the respective models. For example, the LCA calculations looked specifically at scenarios based on individual sets of assumptions. As described in the **Potential Impact of Assumptions on Results** section, these results could change if assumptions varied or if multiple fuels were used in harmony.

The TEA utilizes a number of assumptions, including the NETL calculation (see **Appendix C**). There are potential gaps in these TEAs where low carbon fuel production technologies are still under research, and long-term costs of these pathways are uncertain.

There is a limitation to using the cost parity approach when finding the required incentives for each fuel. This approach found the cost of incentive per fuel (e.g. kg H_2). However, the energy content of each fuel is not equivalent (e.g. LHV H_2 vs. LHV NG).

In addition, since the OBBB was recently signed in July 2025, its potential long-term impacts were not incorporated into this case study's optimization modeling. The bill aims to enhance domestic oil and gas production and will likely expand the Gulf Coast's role in bolstering national energy security. Further analysis will be needed to assess the impacts of the OBBB on the region's energy trends, infrastructure development, and the competitiveness of emerging fuels.

Required Incentive Limitations

The required incentive values were calculated for each analysis type (LCA, TEA, NEMS) because the values cannot be calculated for all three analyses simultaneously, and the inputs/outputs are not all available. Incentive calculations for each analysis were based solely on relevant datatypes for each analysis, and individual sets of results and discussion were provided for each analysis. For example, CO_2e emissions are irrelevant in NEMS and TEA, so renewable CI is discarded from incentive calculation for each renewable technology (i.e., $CI_{Renew} = 0$). Since the LCA has the upstream CO_2 emissions data available, the "life cycle" incentives take these data into account. However, since costs would otherwise be unavailable, the levelized costs for the LCA incentives were calculated based on what was provided by the TEA, with an unweighted average cost applied for the electrolysis scenario.

Another important aspect to consider while comparing the NEMS results with the TEA results is that the former are marginal prices for the product while the latter are levelized costs. Marginal prices from NEMS reflect only the on-site production costs, including feeds, utilities, and facility costs. These can be considered as impacting the consumer of the product. The levelized cost from the TEA includes not only production costs, but also capital and set up costs. These can be considered as impacting the producer of the product. Despite these limitations for the different incentive values calculated across analyses, the conclusions drawn generally did not change between analysis type due to similar trends across cases.

Key Challenges and Potential Solutions

Workforce Development

Successful emerging fuel adoption requires attention to energy system resilience and modernization, especially in regions historically reliant on fossil fuels. One key aspect of this is workforce development, as the availability of skilled labor is not keeping up with increasing demand in the rapidly evolving energy landscape. The World Economic Forum reported that global demand for green skills increased by 40% from 2015 to 2023, but only 13% of the global workforce currently possess the skills needed to meet this demand (Sue Duke 2023). This gap in technical expertise and experience can slow the adoption of emerging technologies and practices, and requires intentional collaboration across industry, academia, and government bodies to align the current workforce with skill demand. Investing in new training opportunities and leveraging existing skills for a range of emerging jobs through upskilling and reskilling is critical to enabling a low-carbon energy system and the successful adoption of new technologies and fuels (Betony Jones et al. 2023).

Cross-collaboration between industry, academia, and government is already occurring across the Gulf Coast region to bridge the gap between skill demand and available workforce. Several Gulf Coast states have enacted policy to support the development of fossil-fuel workforces in parallel with the greater energy transition and evolving energy mix. Alabama is addressing this concern by creating financial incentives to attract high technology companies and workers to rural and low growth areas and job tax credits to grow its technology workforce. Other state policies emphasize skills development and training for transitioning fossil fuel workers. New Mexico has enacted the greatest proportion of these policies in the Gulf Coast, including the Energy Transition Act of 2019 and the resulting Coal Transition Programs. In 2021 New Mexico established a Sustainable Economy Task Force to develop a strategic plan for transitioning the state economy away from reliance on natural resource extraction. Other industry-lead initiatives and programs have emerged in the region as well, including SkillStream, a collaboration between the Arkansas Advanced Energy Foundation (AAEF) and Metroplan, and the Texas Climate Jobs Project (Texas Climate Jobs Project et al. 2024) (Central Arkansas Planning & Development 2025). Academia-lead programs such as the Gulf Research Project (GRP) of the National Academies of Sciences, Engineering, and Medicine are providing significant funding to develop training programs and pathways for Gulf Coast residents to enter high-quality jobs that support the energy transition. GRP recently awarded over $3 million to seven projects dedicated to providing the skills, knowledge, and credentials needed to develop the energy workforce to meet future energy system needs (National Academy of Sciences 2025).

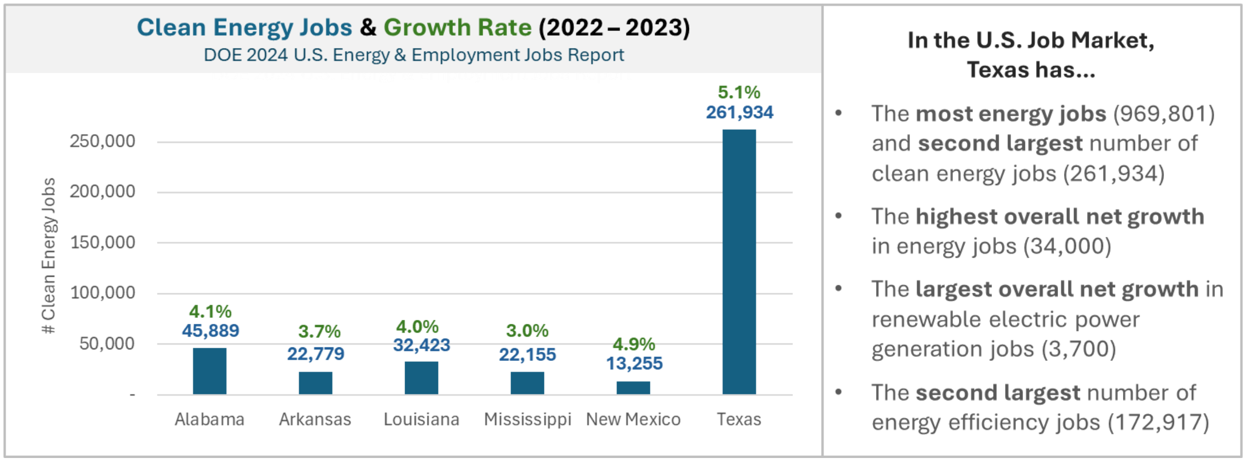

Figure 44. Clean energy job growth in Gulf Coast states (data from the DOE 2024 U.S. Energy & Employment Jobs Report)

Strategic Modernization of Infrastructure

Modernization of natural gas infrastructure is a long-term priority for natural gas companies and is critical to the successful integration of H_2, SNG, and RNG into existing pipeline systems. To accommodate blends of emerging fuels, the existing natural gas network must evolve to safely and efficiently handle blended or alternative fuel streams. Legacy pipeline systems (e.g., cast iron, bare steel) might not be compatible with the chemical and physical characteristics of emerging fuels. Upgrading these systems will be essential to ensuring fuel integrity, minimizing leak risks, and enabling broad adoption of low-carbon energy technologies across residential, commercial, and industrial sectors.

State-level efforts in the Gulf Coast vary in progress and focus. Texas has begun integrating methane emission reduction initiatives with infrastructure resilience programs, driven by regulatory agencies such as the Texas Railroad Commission and the Texas Commission on Environmental Quality (TCEQ) (Texas Commission on Environmental Quality 2023). In 2024, Texas received approximately $14 million dedicated to gas pipeline replacement projects from Natural Gas Distribution Infrastructure Safety and Modernization Grants (NGDISM) (Pipeline and Hazardous Materials Safety Administration, n.d.). Alabama has focused on incentivizing modernization efforts, including grants and partnerships to upgrade gas delivery systems and enhance workforce training to support new technologies. Several cities in Alabama also received fundings from PHMSA to replace decades old natural gas pipeline (Kyra Purvis 2023). Louisiana, with its significant natural gas infrastructure and industrial demand, has advanced resilience planning through the Louisiana Public Service Commission and state climate task forces, promoting strategic infrastructure upgrades and emergency preparedness for extreme weather. Mississippi's efforts are emerging, with preliminary programs targeting leak reduction and system reliability improvements, though comprehensive modernization plans are still under development.

Despite this progress, the region faces several key challenges in modernizing its gas infrastructure. Many pipeline systems are decades old, composed of cast-iron or steel that can be prone to leaks and corrosion. These vulnerabilities are amplified when transporting H_2, which can cause embrittlement and increase the likelihood of failure if infrastructure is not specifically designed or retrofitted for compatibility. The Gulf Coast's exposure to hurricanes, floods, winter storms and extreme heat places added stress on the infrastructure, demanding resilient system designs and weatherization that can withstand both gradual degradation and natural elements.

To address these challenges, a coordinated approach to gas infrastructure modernization could play an important role. This includes prioritizing the replacement of high-risk pipeline segments, especially in urban or industrial zones expected to see early adoption of H_2 and RNG. Investments in advanced materials, coatings, and seals compatible with H_2 can extend infrastructure lifespans while improving safety. Integrating weatherization measures, leak detection, and system automation will be critical to ensuring operational continuity during climate-related disruptions. Finally, aligning regulatory frameworks, funding/financing mechanisms, and stakeholder collaboration across Gulf Coast states will be vital to scaling resilient and reliable gas infrastructure.

Other Investments to Support Adoption of Emerging Fuels

There are several opportunities for additional research and development to improve the immediate prospects of emerging fuels. In particular, emphasis should be placed on achieving larger scales and throughputs as well as higher thermal efficiencies and manufacturing cost reductions.

Based on the promising economic profiles seen from the TEA, LCA, and optimization modeling results for plasma pyrolysis-based H_2 and MSW-based RNG, research investments toward larger scale and more efficient biodigester and/or thermal biomass gasifier technologies could reduce the fuel production cost and foster the adoption of H_2 and RNG in the Gulf Coast. Anaerobic digesters are one of the least challenging technologies to produce RNG, but recover RNG at a much slower, scale restricted rate. Efficiency improvements to many existing anaerobic digesters will need to maintain optimal conditions for methanogenesis and may include feedstock pre-treatment, in situ, and ex-situ technology advancements.

Local market research can help identify opportunities to improve the standard supply chain models for emerging fuels, such as by exploring the potential for co-processing of multiple feedstocks at larger, centralized facilities. Non-traditional feedstocks such as pulp/ paper waste and research in feedstock pre-treatment practices will also be important to achieving competitive lifecycle emission reductions, minimized costs, and reliable access to feedstocks. Overall, it is necessary to expand investments toward improving the supply chains of local biomass resources and long-term fuel biomass storage technologies to mitigate feedstock shortage impacting production volumes.

End Use Compatibility

Additional studies to identify process and material compatibility improvements to reduce the costs and increase efficiency will be key to scaling H_2, RNG, SNG. Specific end use equipment will require replacements or retrofit technologies to achieve compatibility with H_2 blends. Continued investments in developing low-cost retrofit technologies will allow a broader spectrum of end users for pure H_2 and higher H_2 blends.

Prospects for reducing the costs of deblending of H_2 should be further investigated, especially with respect to specific sensitive end users. Cost-benefit analysis of deblending will need to consider the system specific benefits, and ideal locations in the delivery network as a function of applicable end users. This is especially necessary as end users serviced by a single distribution main can include mixed-use customers which have different H_2 content needs.

Supportive Programs

Market adoption of new technologies can be challenging, even after large scale research pilot studies are successfully developed. Immediate opportunities for emerging fuels will incorporate existing infrastructure, facilities, and equipment to produce, deliver and utilize H_2, RNG and SNG. This includes strategic research to understand cost-effective pathways to scale emerging fuels, as well as options for cost-recovery mechanisms, and funding programs. Incentive programs aimed at both fuel and feedstock producers can improve the economic outlooks for emerging fuel production. For example, programs which support renewable electricity producers to inject surplus electricity into the grid can have positive implications for emerging fuel producers.

Access to Critical Minerals for H_2 Production

The production of electrolyzers depends on several critical minerals, making regional access to these materials essential for scaling electrolysis-based H_2 production pathways. As of 2024, the United States continues to rely heavily on international suppliers for over 80% of its rare earth minerals, underscoring the vulnerability of the domestic supply chain. In response, there is growing interest in exploring alternative, domestically sourced mineral supplies, particularly from produced water and subsurface brines found in the Gulf Coast region. These waste streams, generated as byproducts of oil and gas operations, are notably rich in valuable minerals such as lithium, nickel, cobalt, magnesium, strontium, and rare earth elements, all of which are critical to the manufacturing and operation of electrolyzers (U.S. DOE Fossil Energy and Carbon Management, n.d.). To promote research in this area and harness these resources, funding has been allocated to support related studies. For example, Texas Tech University recently received research funding from the Department of Energy, including grants exceeding $5 million in 2024 and early 2025, to investigate the availability and extraction techniques for critical minerals from the Gulf Coast and Permian Basin brines (Ashlyn Grotegut and Ashley Rodgers 2025). These research initiatives aim to develop advanced membrane-based recovery technologies to enable efficient and cost-effective extraction, while simultaneously offering environmental benefits such as reducing freshwater usage and minimizing waste disposal.

Along with the research efforts, regulatory and policy frameworks have also begun to support the domestic extraction of critical minerals. In 2022, the federal government authorized the use of the Defense Production Act (DPA) Title III authorities to promote the development of domestic geologic extraction and processing of key critical minerals such as cobalt, lithium, nickel, and graphite, further bolstered by funding allocations in climate and infrastructure legislation (U.S. Department of the Interior and U.S. Geological Survey 2025).

In parallel with resource development, selecting electrolyzer technologies with mineral demand profiles that align with regional mineral availability offers an immediate path to mitigating supply risks. Proton Exchange Membrane (PEM) electrolyzers, for example, require lower quantities of scarce minerals such as iridium and rare earth elements compared to solid oxide or alkaline electrolyzers, making them better suited to leverage the Gulf Coast's mineral resource profile efficiently (Greenwald et al. 2024).

The advances in domestic mineral extraction, supported by strategic policy incentives and aligned with technology choices optimized for mineral efficiency, position Gulf Coast to become a critical hub in the national clean energy transition. By integrating regional mineral resource development with infrastructure modernization and technology deployment, the Gulf Coast can reduce dependence on foreign mineral imports, enhance system resilience, and support scalable, low-carbon H_2 production.

Conclusion

Policy incentives and technological advancements can enable the region to lead the transition of next-generation energy systems, supporting both economic growth and sustainability.

With key suppliers of valuable fuels and exports, the Gulf Coast region reinforces national energy security and interregional commerce. Additionally, the Gulf Coast is home to the only currently operating H_2 pipeline system in the United States. Given the region's well-established oil and gas infrastructure, it presents a strong foundation for the development of H_2 hubs, which could serve as critical assets in the transition toward lower-carbon energy.

The Gulf Coast, mostly due to Texas and Louisiana, serves as a cornerstone of the nation's heavy industry, featuring a strong presence of power plants, extensive oil and gas infrastructure, and energy imports/exports. This industrial concentration ensures a consistent and abundant supply of CO_2, positioning the region as a viable location for SNG production and other fuel or material initiatives. In addition, the region has a robust and well-connected existing natural gas network and vast additional infrastructure to support fuels like SNG. However, the modeling in this study reveals that for SNG to become a competitive option within the broader energy market, well-structured incentives will be necessary to drive commercial adoption and investment is generally economically unfeasible in the Gulf Coast due to the typically high costs of H_2 production and low emissions benefits compared to other options, such as RNG.

As of 2023, the cost of producing low-carbon fuels in the Gulf Coast varies widely depending on the technology, feedstock, and geographic location. Among H_2 options, the most cost-effective pathway is ATR of natural gas with CCS in Texas, with a production cost of $1.40/kg. In contrast, the most expensive H_2 pathway involves producing H_2 via SMR of RNG with CCS in New Mexico, at a steep $11.45/kg.

For RNG, the lowest cost is achieved through LFG conversion in Texas, priced at $29.80/MMBtu. However, RNG produced from woody biomass in New Mexico represents the upper end of the cost spectrum at $189/MMBtu, primarily due to limited regional feedstock availability and high capital costs.

Delivery and infrastructure considerations are critical to assessing deployment feasibility. RNG and SNG can typically be transported through existing natural gas pipelines, provided that the gas meets stringent quality standards. H_2 transport, however, poses additional complexity. According to HDSAM modeling adapted to Gulf Coast parameters, both liquid and gaseous H_2 delivery systems require higher infrastructure investments. Interconnection costs also vary significantly by source, approximately $13/MMBtu for LFG-derived RNG and up to $24/MMBtu for woody biomass-derived RNG. Due to H_2's lower volumetric energy density, H_2 -specific pipelines are estimated to cost 2–15% more per unit of energy delivered compared to natural gas pipelines.

End-use compatibility plays a key role in adoption. Residential and commercial sectors across the Gulf Coast are positioned to be early adopters of emerging fuel blends, given their relatively flexible equipment standards. However, certain industrial applications, including compressed natural gas (CNG) fueling stations and steel or glass manufacturing facilities, require tight gas quality specifications that could be compromised by H_2 blending. For these sensitive sectors, emerging technologies such as H_2 de-blending systems may be crucial, allowing utilities to tailor gas composition based on end-user needs while maintaining system-wide H_2 integration.

Infrastructure expansion and modernization efforts are also underway. GIS-based optimization has identified key opportunities for replacing aging cast iron and bare steel pipelines and for expanding the pipeline network into underserved regions, such as southern Alabama and parts of New Mexico. These upgrades will enhance safety and reliability while increasing compatibility with emerging low-carbon fuels.

From a regulatory standpoint, oversight is split across federal and state levels. Federally, the Pipeline and Hazardous Materials Safety Administration (PHMSA) governs pipeline safety, while the Federal Energy Regulatory Commission (FERC) manages gas tariffs and operational guidelines. However, the regulatory classification of H_2 remains ambiguous, and its status as a “natural” or “artificial” gas affects which agency holds jurisdiction, especially for H_2 blends. This lack of clarity could hinder project approvals and investment certainty.

At the state level, Texas, Louisiana, and Alabama have implemented policies to support natural gas development and incentivize RNG and H_2 production. New Mexico stands out for its emphasis on emissions reduction and equitable transition strategies, including regulatory support for energy efficiency and low-carbon technologies. Notably, only Louisiana currently holds Class VI primacy, which allows it to permit carbon capture and storage projects independently from the EPA, a key advantage for scaling carbon management solutions.

Strategically, RNG emerges as the most promising near-term solution, particularly when derived from MSW, due to its relatively favorable cost profile and compatibility with existing infrastructure. H_2 shows long-term potential but requires continued research and development, targeted subsidies, and major infrastructure investments to reach commercial viability. SNG, while technically feasible, is currently cost-prohibitive under most market conditions.

By leveraging these resources, the region could leverage existing gas infrastructure to further diversify its energy portfolio and to enhance energy security. H_2’s potential within the region, however, is more uncertain and is dependent on the unknown benefits that ongoing research will have on production technology performance. Of the technologies assessed in this study, gasification/pyrolysis technologies were found to have the highest potential. Repurposing existing infrastructure remains a pivotal strategy to accelerate carbon emission reduction efforts. Leveraging the Gulf Coast’s vast network of natural gas assets offers a lower-cost and lower-risk approach to integrating H_2 and RNG into the regional energy mix.

Finally, as the energy system evolves, workforce development and economic transition will be essential. States such as New Mexico and Alabama are taking proactive steps by investing in the retraining of fossil fuel workers, supporting rural economic development, and fostering talent pipelines for new energy technologies. These initiatives will ensure that communities and workers are positioned to benefit from the growing low-carbon economy.

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