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GTI ENERGY RAISE
Reliable Affordable Infrastructure for Secure Energy

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TECHNICAL SUMMARY

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.
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 blendable into NG systems
Lifecycle Analysis (LCA)	Estimation of fuel specific GHG emissions impact
Municipal solid waste (MSW); source separated	Discarded waste originating from mixed sources (i.e., households, commercial businesses) including organics such as yard trimmings, food and 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.
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 blendable into NG systems.
Technoeconomic analysis (TEA)	Cost analysis of fuel pathway

Preface

This report provides a synopsis of the analysis methodologies and findings of the main report: **Utilizing Gulf Coast Natural Gas Infrastructure for Emerging Fuels**, developed by the **Reliable Affordable Infrastructure for Secure Energy (RAISE) collaborative.**

For more information, please visit the RAISE website: https://www.gti.energy/raise/

Introduction

In the midst of evolving energy infrastructure and 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 promising solutions to further diversify the nation's energy portfolio, enhance energy security, and provide opportunities to increase low-carbon energy supply, all while capitalizing on the pre-established network of US natural gas infrastructure. This case study evaluates the adoption potential of these emerging fuels in the Gulf Coast region, as defined by the Petroleum Administration for Defense Districts (PADD). Gulf Coast region, defined as PADD 3, comprises of New Mexico, Texas, Arkansas, Louisiana, Mississippi, and Alabama (**Figure 1**).

Figure 1. Five U.S. regions, as defined by the Petroleum Administration for Defense Districts. Study Focus Area: Gulf Coast Region States (Source: EIA)

The Gulf Coast case study explores the integration of emerging fuels at both conservative and optimistic adoption rates using average overall blending targets of 5 and 20% by volume, since it is anticipated that some end-uses can accept higher blends in the Gulf Coast region. 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. **Table 1** below summarizes key insights from this Gulf Coast case study analysis. Further details about the analytical approach and methodology are provided in the body of this executive summary.

Table 1. Gulf Case Study Key Insights

Resource Availability	• Texas and Louisiana lead in agricultural and forest biomass availability. • RNG is ideal for Eastern Arkansas, while H_2 is better aligned with Texas and Louisiana's infrastructure and energy landscape. • The Gulf Coast is particularly well-suited for CO_2 capture markets due to its extensive and mature industrial base. • There is significant CO_2 availability associated with power plants and many industrial sources in the region that can be leveraged for SNG production.

Techno-economic Analysis	• SMR with CCS, ATR with CCS, and plasma pyrolysis are the lowest-cost H_2 production pathways in the region.
	• Costs range from:
	  ○ \$1.40-2.84/kg H_2 produced via SMR w/ CCS or NG ATR w/ CCS,
	  ○ \$1.87-3.74/kg H_2 produced via NG plasma pyrolysis
	• Modeling results indicate that while plasma pyrolysis was estimated to require the lowest carbon incentive (benefiting from the region's low-cost natural gas and potential for commercial scalability), it remains an early-stage and immature technology at this time.

	• Levelized costs of RNG and SNG pathways show greater variability across states, as compared to H_2 pathways. ○ Costs differ by nearly twofold between some states.

Lifecycle Analysis	• Calculated CI scores for H_2 pathways vary significantly by state, depending on the feedstock and production technology utilized.
	  ○ For SMR w/ CCS and ATR w/ CCS, state-level CIs range from 2.6-3.9 kg CO_2e/ kg H_2 (22-30 g CO_2e/MJ H_2).
	  ○ Average H_2 pathways have lower CIs than those of SNG and RNG pathways: 38 g CO_2e /MJ H_2, 248 g CO_2e /MJ RNG, 306 g CO_2e /MJ SNG.
	• State-level CIs range from ~12-19 kg CO_2e/kg fuel across all RNG and SNG pathways (~250-400 g CO_2e /MJ fuel).
	• Lowest SNG CI was observed with ATR w/ CCS for all states.
	• RNG produced via MSW gasification have lower CIs compared to all SNG cases.

Cost-Benefit Analysis	• Most H_2 technologies are not economically competitive without financial and policy incentives. • Reforming technologies could become viable with further cost reductions through innovation and supply chain improvements. • RNG, particularly from MSW-based biodigesters, yields the most favorable carbon economics. Despite higher TEA costs (~\$600–\$1,600/ton CO_2), the LCA for MSW biodigesters yields negative CO_2 emissions and a calculated incentive need of \$157/ton CO_2. • SNG has the highest cost and least favorable emissions profile under current modeling assumptions. The TEA and NEMS models place required incentives above \$800–\$1,000/ton CO_2.

	• H_2 pathways have notably lower levelized costs and carbon intensities in comparison to SNG and RNG pathways.
	  ○ Louisiana and Texas will likely access more cost-recovery from CI-dependent incentives for H_2 produced via SMR/ATR w/ CCS and natural gas pyrolysis, due to lower levelized costs.
	  ○ Arkansas will likely rely the most on incentives due to having the highest levelized costs for H_2 produced via SMR/ATR w/CCS and natural gas pyrolysis.
	• Due to greater variability of state-level levelized costs for RNG and SNG pathways, states such as New Mexico, Arkansas, and Louisiana are more likely to benefit from CI-based incentives for RNG and SNG production due to their higher levelized costs.

Infrastructure Readiness	• The cost to repurpose NG pipelines for H_2 and H_2 blend service is estimated to be 10-35% of the cost of new pipeline construction. However, actual costs will depend on factors such as pipeline diameter, location, material type, and condition of the pipeline. • RNG and SNG offer the advantage of being drop-in fuels as they are chemically identical to conventional natural gas. • Texas and Louisiana would benefit the most from access to low-carbon H_2 to reduce emissions from ammonia production, petroleum refining, and other industrial markets.

Opportunities

- Workforce development is critical for the successful adoption of emerging fuels. Cross-sector collaboration among industry, academia, and government is essential to close the skills gap through upskilling, reskilling, and strategic training initiatives.
- Modernization of natural gas infrastructure is a long-term priority for natural gas companies and is critical to the successful integration of emerging fuels into existing pipeline systems.
- Additional studies to identify process and material compatibility improvements to reduce the costs and increase efficiency will be key to scaling emerging fuels.
- Public (state and federal government and regulatory bodies) and private (utilities, manufacturers, investors) partnerships can help share risk and resources and align infrastructure investments with broader emissions reductions goals.

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 (**Table 2**).

Table 2. 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

- 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

Case Study Approach

The intent of this case study is to identify H_2, SNG, and RNG opportunities, and regional polices and investments that can support emerging fuels adoption in the Gulf Coast. To accomplish this goal, the study integrates three core analyses: Technoeconomic Analysis (TEA), Lifecycle Analysis (LCA), and Regional Fuel Pathway Optimization Analysis. **Figure 2** illustrates the comprehensive analytical approach undertaken in this study.

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.

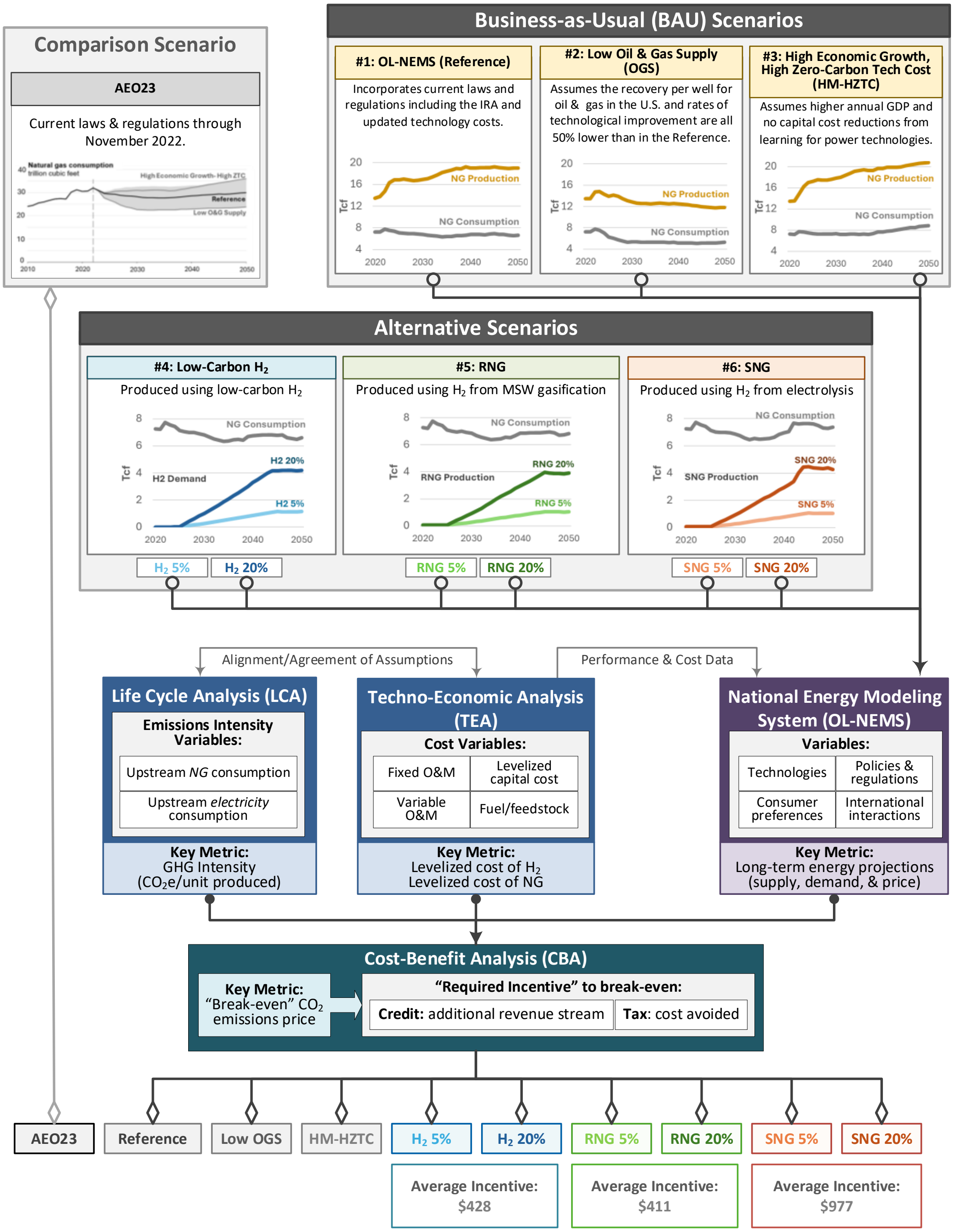

Figure 2. Integrated analysis of cost, emissions, and deployment strategies for H_2, RNG, and SNG pathways

Optimization Model

The National Energy Modeling System (NEMS), developed by the Energy Information Administration (EIA), simulates various U.S. energy market scenarios through 2050. Its outputs inform the Annual Energy Outlook (AEO), which projects energy trends. This case study used the 2023 AEO and OnLocation's customized NEMS version (OL-NEMS) to explore various energy demand scenarios in the Gulf Coast, comparing proactive, policy-driven approaches with more constrained market conditions. The results provide insights into how emerging fuels can be scaled under various market conditions in the Gulf Coast region.

Description of Business-as-Usual (BAU) Scenarios

To consider various economic market conditions, four BAU scenarios are evaluated with OL-NEMS. 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 3** 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 3. 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 Reference Case	Includes technology cost updates and IRA and other policies implemented since AEO23 was released	**Supportive**

#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**

The basis for the selection of the BAU scenarios was to review economic conditions which generate a neutral, supportive, and unsupportive outlook for the adoption of emerging fuels.

Blending Range Assumptions

Some industrial end users like LNG and CNG facilities are forecasted to only be able to accept 5 vol% H_2 blends into natural gas, whereas residential end uses are hypothesized to be able to accept up to 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. Using 5 and 20 vol% and 2050 in this study provide conservative and optimistic blending scenarios. To avoid abrupt shifts in the energy system, the blending rates are assumed to linearly increase to their target between 2026 and 2045. The analyses consider resource availability, projected costs, associated emissions, and cost-benefit where applicable.

OL-NEMS Emerging Fuel Scenarios

The OL-NEMS fuel case modeling largely followed the assumptions of the BAU AEO23 Reference case with the exception of the following assumptions summarized in **Table 4**.

Table 4. Summary of OL-NEMS Custom Assumptions for each fuel case

OL-NEMS Assumptions	H_2	RNG	SNG
System Blend	**5, 20 % vol.**	**5, 20 % vol.**	**5, 20 % vol.**
Pathway(s)	LowC H_2, excluding NG SMR, ATR	RNG fed SMR, ATR with MSW	H_2 via electrolysis w/ methanation
Costs	TEA results	Function of H_2 price. Based on sum of marginal price and delivery adder	Function of H_2 price, CO_2 price from capture, and CO_2 transport costs.

			Based on sum of marginal price and delivery adder

Each of the fuels is considered to be blended into natural gas pipelines at rates of 5 vol% and 20 vol%, to account for minimal and optimistic adoption scenarios into natural gas delivery networks. These two blending cases assume there will be a range of adopted blend rates delivered to customers, depending on their location and end-use specific needs.

Pathways Evaluation Inputs and Assumptions

Fuel-specific costs, emissions, and regional feedstock availability are captured through TEA, LCA, and resource availability analyses. **Figure 3** summarizes the variables used in these assessments and the modeling inputs that inform the cost-benefit analysis.

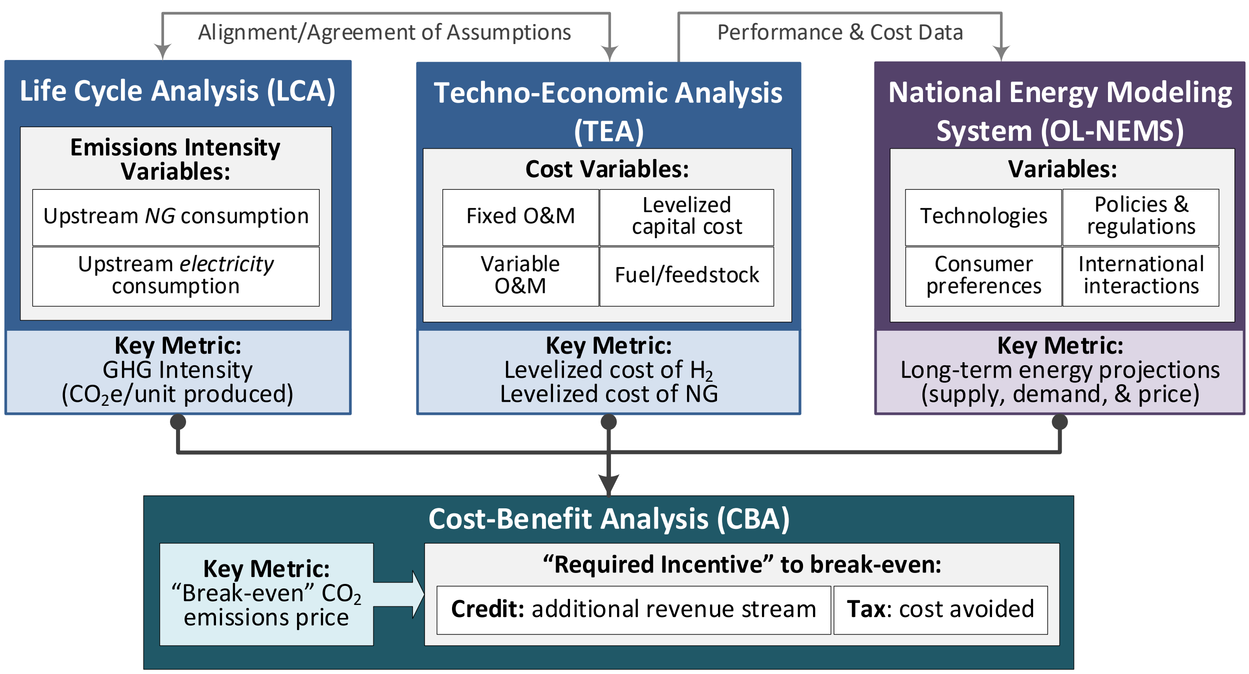

Figure 3. Summary of key TEA, LCA, and resource availability inputs used to inform the cost-benefit analysis.

Techno-Economic Analysis (TEA)

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. 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.

Life Cycle Assessment (LCA)

The LCA estimates the cradle to gate carbon intensity for hydrogen production using the DOE's Hydrogen Shot methodology and the Open Hydrogen Initiative (OHI) toolkit. While the toolkit provides default parameters, adjustments were made for low-carbon hydrogen cases involving RNG and plasma pyrolysis. Custom unit-process models were made and assessed using openLCA for SNG and RNG production pathways to capture their unique characteristics. Regional variations in upstream GHG emissions from natural gas and electricity were based on NETL and FERC data, adjusted to PADD regions using state-level consumption data. These variations primarily influence GHG intensity, while system-level parameters like CCS efficiency and methane leakage remain constant across locations.

Cost Benefit Analysis (CBA)

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, 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 such as 45Q and 45V (U.S. Congress, n.d.). These incentives represent the "break even" CO_2 emissions price required for the given fuel to reach cost-parity with natural gas. 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.

Resource Availability

To evaluate the potential for producing H_2, RNG, and SNG in the Gulf Coast, a detailed data collection effort focused on key feedstocks (e.g., agricultural and forest residues, municipal solid waste, natural gas reserves, and landfill gas) was conducted. Data from federal sources including the EPA, USDA, EIA, NETL, and DOE's 2023 Billion Ton Report, informed the analysis. Landfill gas estimates were based on the EPA's LMOP database, though competing uses like onsite energy generation were not considered. Similarly, alternative uses of other feedstocks were excluded from the analysis.

Summary of Gulf Coast Findings

The Gulf Coast region holds over 55 million tons of biomass, primarily MSW alongside agricultural and forest residues and landfill gas, with Texas leading in landfill gas (LFG) production. Agricultural residues are concentrated in Northeast Texas, Eastern Louisiana, and Eastern Arkansas. Forest residues are more abundant in the region except in Western and Central Texas and Southeastern Louisiana. MSW is concentrated in urban centers, particularly Dallas-Fort Worth and Houston. Texas alone currently generates 367 million standard cubic feet per day of landfill gas from over two million tons of landfill waste across 161 sites, accounting for two-thirds of the region's landfill energy potential.

In addition to biomass, the region contains over 1.3 trillion cubic feet of natural gas and abundant CO_2 sources, especially from natural gas power plants, which emit over 300 times more CO_2 than ethanol plants and 18 times more than cement plants. The Gulf Coast also has strong renewable energy potential with wind in Texas, solar across the region, hydroelectric in Alabama and Arkansas, and geothermal in Texas and New Mexico. These diverse resources position the region as a leading hub for producing and exporting emerging fuels like RNG, SNG, and hydrogen.

Producing and Delivering Emerging Fuels in Each State

State-level fuel production costs for producing low-carbon H_2, RNG, and SNG were developed using state-specific data for natural gas costs, electricity costs, labor costs, CO_2 Transmission and Storage (T&S) costs, point source CO_2 availability, and other resource availability. Note that the boundary for the production costs is plant gate-to-gate.

For H_2 pathways (H2-1 to H2-7), as shown in **Table 5,** fuel/feed costs make up most of production costs, while H2-8 (electrolysis) is mainly driven by variable O&M. SNG production costs are almost entirely fuel/feed-related. For RNG pathways (**Table 6**), capital costs dominate except in RNG-4 (LFG to RNG), where fixed O&M is the largest cost component.

Table 5. Summary of H_2 Pathway Costs

Production Cost Findings for H_2 Pathways	
Most Cost-Effective Pathways Ranked (All Gulf Coast States)	1) Natural gas ATR w/ CCS (case H2-2) 2) Natural gas SMR w/ CCS (case H2-1) 3) Natural gas pyrolysis (case H2-7)
State-Level Findings	• Most Cost-Competitive: Natural gas ATR w/ CCS (case H2-2) in **Texas at $1.40/kg H_2** • Most Expensive: RNG SMR w/ CCS (case H2-5) in **New Mexico at $11/kg H_2** • **Electrolytic H_2: Lowest cost in Mississippi** using electricity from combined wind and solar with storage (case H2-8a/b) at **$4/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.

Table 6. Summary of SNG and RNG Pathway Costs

Production Cost Findings for SNG Pathways	
Most Cost-Effective Pathways Ranked (All Gulf Coast States)	• Lowest Cost: High-purity CO_2 from ethanol fermentation (SNG-4a/b) in Texas at **$48/MMBtu** • Highest Cost: CO_2 from natural gas power plants (SNC-1c) in Louisiana at **$76/MMBtu** • When examining RNG and SNG pathways together, LFG to RNG (RNG-4) in Texas has lower cost than all SNG/RNG pathways

State-Level Findings	• Mississippi, New Mexico, and Texas offer the lowest SNG costs due to cheaper electrolytic H_2. • In New Mexico, the most economical option (SNG-1a/b) combines CO_2 from a power plant with electrolytic H_2 from wind and solar.
Production Cost Findings for RNG Pathways	
Most Cost-Effective Pathways Ranked (All Gulf Coast States)	• Lowest Cost: LFG to RNG (RNG-4) in Texas at **$33/MMBtu** • Highest Cost: Woody biomass gasification (RNG-2) in New Mexico at **$189/MMBtu**
State-Level Findings	• In most Gulf Coast states, LFG to RNG (RNG-4) is the lowest-cost option except for New Mexico where SNG-1a/b is cheaper
SNG/RNG Interconnection Cost Findings	• **SNG (SNG-1 to SNG-4):** Often co-located with CO_2 sources local to natural gas infrastructure • **MSW to RNG (RNG-1):** Lower interconnection cost due to typical landfill proximity to natural gas infrastructure • **Biomass to RNG (RNG-2, RNG-3):** Higher costs due to remote locations • **Dairy RNG:** $10–$30/MMBtu depending on project size and pipeline extension needs • Interconnection distances and installation costs will vary across the region. • The scaling of RNG and SNG will require additional interconnection and distribution main pipe to connect producing facilities to the delivery infrastructure, as well as account for current downstream pipe capacities.

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.

Figure 4 illustrates the range of economic stimuli necessary to promote the adoption of some of the technologies explored in this study.

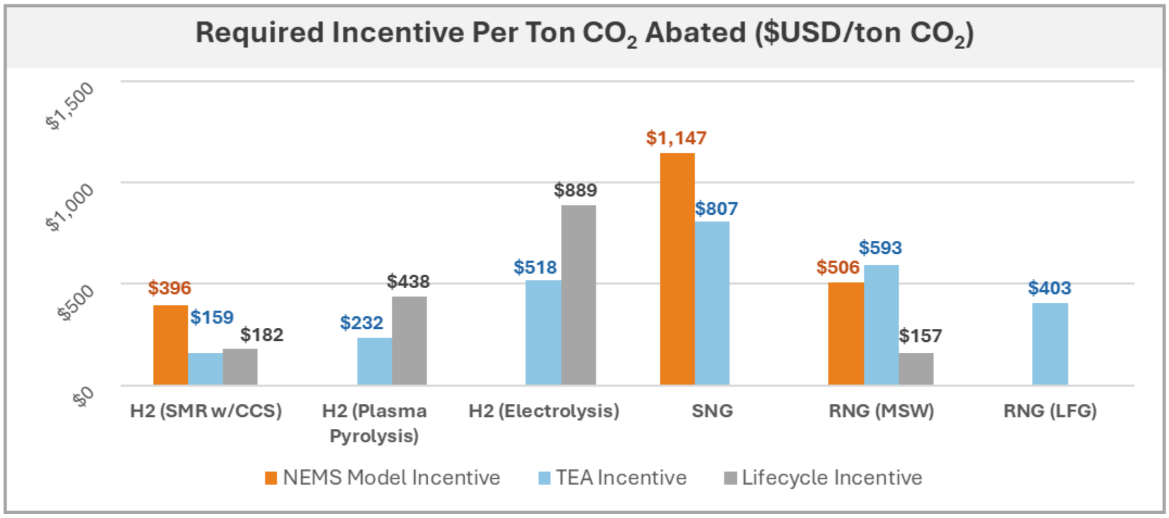

Figure 4. Required incentives for emerging fuels ($/ton of CO_2 avoided)

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 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).

Based on the calculated required incentive calculations, **SNG pathways and H_2 produced via electrolysis will require the most significant incentives to scale in the Gulf Coast region.**

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. The high variable O&M costs for electrolysis could be reduced either by major decreases in renewable electricity prices or electrolysis technology efficiency improvements.

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 5 compares state differences in fuel pathway levelized costs ($/kg fuel) to respective carbon intensities (CIs) (kg CO_2e/kg fuel) for the 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.

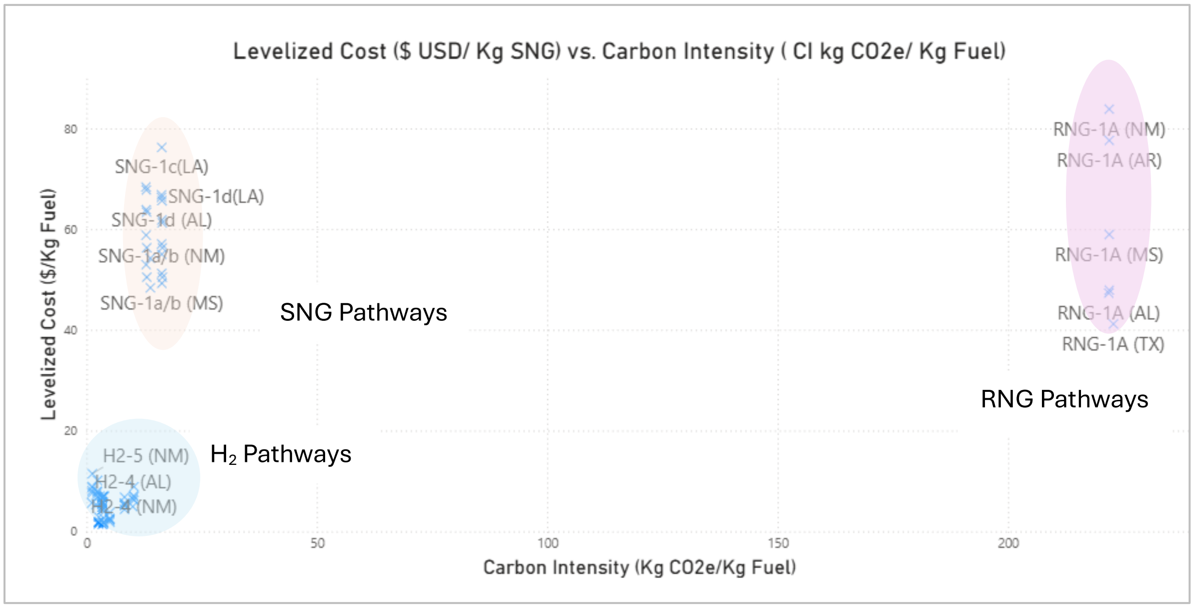

Figure 5. Fuel pathway levelized cost vs. carbon intensity (state-level)

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 6**).

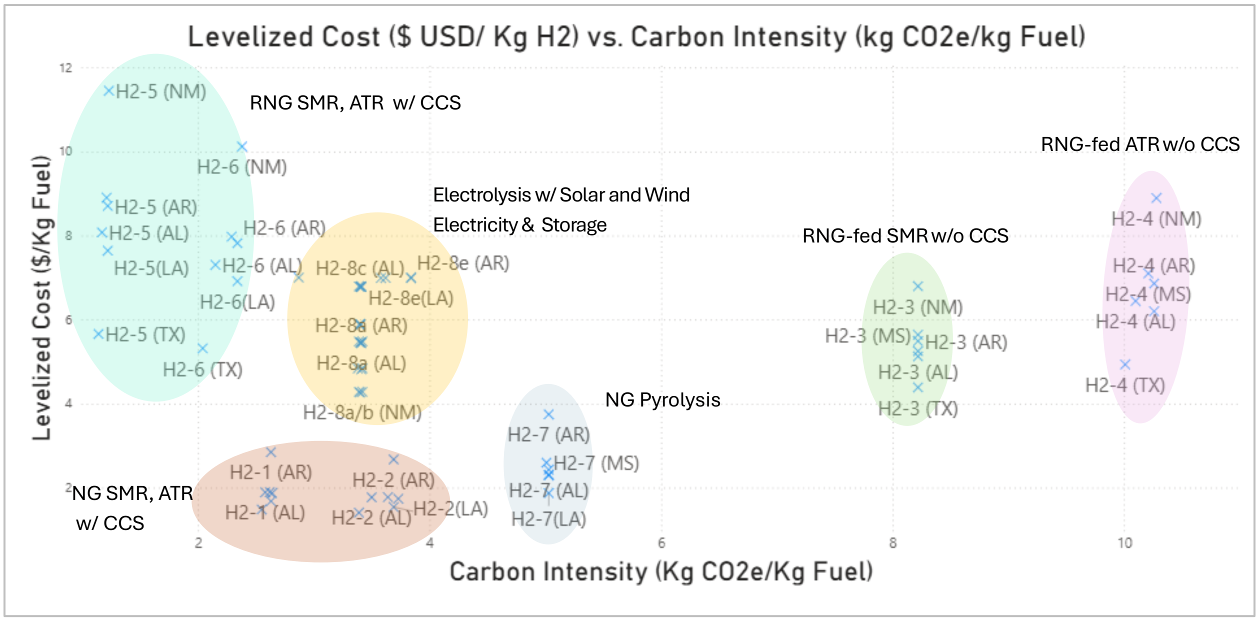

Figure 6. Levelized H_2 cost vs. carbon intensity (state-level)

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/ATR with CCS is currently the most cost-effective H_2 production route and supports 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 6**), 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 more strongly influenced by state-specific factors affecting cost rather than CI, as illustrated in **Figure 7**. States such as New Mexico, Arkansas, and Louisiana are more likely to benefit from CI-based incentives for RNG and SNG production. Comparing these on an energy-normalized basis, the average CI of each of these fuels is 248 g CO_2e/MJ RNG (RNG-1), 276 g CO_2e/MJ SNG (SNG-2), 290 g CO_2e/MJ SNG (SNG-4), and 345 g CO_2e/MJ SNG (SNG-1).

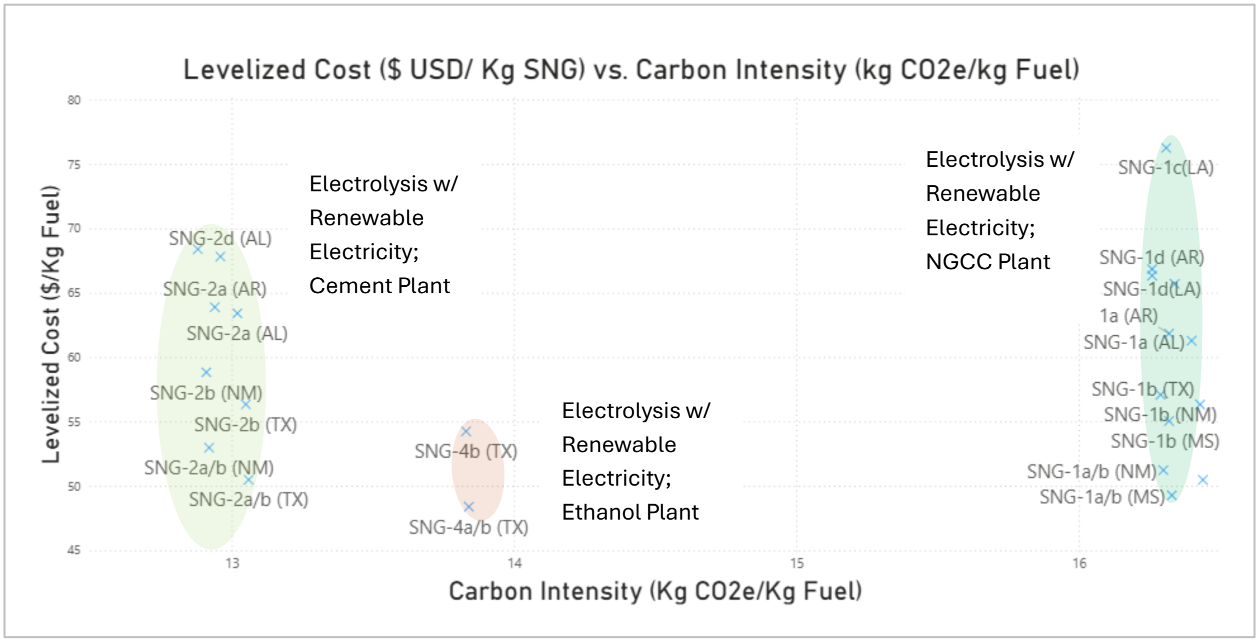

Figure 7. Levelized RNG and SNG cost vs. carbon intensity

RNG pathways show the widest variation in emissions, 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 costs are largely driven by the price of H_2 feedstock, which is fairly consistent across the Gulf Coast states. SNG pathways generally exhibit higher emissions than H_2 pathways but still offer reductions compared to conventional natural gas when CCS is applied. Among the emerging fuel pathways evaluated in this study, SNG offers the least emissions reduction benefit relative to the level of incentives required.

Emissions and End-Use Consideration of Emerging Fuel Pathways

Among all delivery methods, liquefaction dominates GHG intensity, often approaching or exceeding production-related emissions. In contrast, compression, trucking, and pipelines contribute relatively minor emissions, though pipeline delivery includes construction and operational fugitive gases. For RNG and SNG, feedstock type and electricity source are the most significant drivers of life cycle emissions, with biomass and industrial CO_2 sources offering pathways for lower-carbon outcomes.

GHG Intensity by Source:

LCA results across the six Gulf Coast states reveal that hydrogen production via low-carbon electricity (H2-8) achieves similar GHG intensity levels to fossil-based hydrogen with CCS.

Variations in upstream emissions from renewables are minimal across states (±5%), except for biomass-powered electrolysis (H2-8e), which shows up to 30% variation due to differing agricultural feedstocks.

- **RNG Pathways**:
    - RNG-1A (woody biomass gasification) and RNG-1B (MSW anaerobic digestion) are modeled to show the range of emissions.

- **SNG Pathways**:
  - Emissions range from 12.91 (SNG-2d) to 19.75 (SNG-3) kg CO_2e/MMBtu.
  - Green electricity gives lower total CI, except biomass-generated electricity.
  - Minor regional variation in SNG CI mostly from feedstock transport distance.

These values were determined from openLCA models with electricity-specific adjustments, and they assume hybrid sources and scenarios consistent with IPCC AR6 (100-year GWP).

H_2 Delivery Emissions

Different H_2 delivery methods demonstrate considerably variable CIs, as shown in **Table 7**:

Table 7. Summary of H_2 Delivery Method CI Findings

Delivery Method	CI Requirements
Compression	Requires **0.562 kWh/kg H_2 → 0.3 kg CO_2e/kg H_2**
Liquefaction	Requires **9 kWh/kg H_2 → 4.5 kg CO_2e/kg H_2** Added Operations Emissions: 0.9 kg CO_2e/kg H_2 • **Liquefier emissions are the highest CI delivery pathway: 5.4 kg CO_2e/kg H_2**
Truck Delivery (120 km round trip)	Diesel Truck Delivery: **1.28E-04 kg CO_2e/ton-km** • *Truck distribution of liquid H_2 (3.5 tonnes of H_2 per trip)*: **0.05 kg CO_2e/trip** • *Truck distribution of gaseous H_2 (0.6 tonnes of H_2 per trip)*: **0.01 kg CO_2e/trip**
Pipeline Delivery	For 200 km transport distance, calculations yielded **0.6 kg CO_2e/kg H_2 total** emissions, including construction and fugitive emissions for a 30-year, 12″ steel pipeline operating at ~800–900 psig

These estimates generally exclude embodied emissions from the manufacturing of vehicles or equipment (except for pipelines, as noted), in line with standard LCA practices. Values align with findings from Argonne's GREET model.

End-Use Considerations

Economic and environmental assessments of H_2 require comparisons on a head-to-head basis against other conventional natural gas. End uses of hydrogen blends include electricity generation, mobility, or other industrial/commercial/residential applications. In some cases, substituting traditional fuels for new alternatives has no tradeoffs or other concerns, while in others, there are efficiency or operational issues to be considered. Since RNG or SNG are potential drop in fuels for natural gas in end-use scenarios, the cost analysis here focuses on end-use of hydrogen, where more end-use transition is needed.

While hydrogen can replace natural gas in many applications with some retrofitting of infrastructure, it often comes at a significantly higher cost, depending on the production pathway. Emissions benefits are substantial, especially when green hydrogen or low-carbon electricity is used, but infrastructure and technology constraints (such as fuel purity for FCEVs) remain challenges. Continued research can drive future costs down to enable realistically capturing these emissions benefits.

Cost Comparison of New, Retrofitted, and Decommissioning Pipelines

H_2 pipelines are estimated to 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 up to 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 3 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).[1] 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.[2] 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.

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[1] 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.

[2] 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.

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, and material type. Applying the upper end of the EPRI estimate to the EIA range, the cost to repurpose a pipeline in the Gulf Coast may potentially cost $334,000 to $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[3].

Conclusions, Opportunities, and Recommendations

The Gulf Coast is a cornerstone for the U.S. energy and industrial sectors, offering a unique convergence of infrastructure, resources, and expertise that can accelerate the deployment of emerging fuels. With an abundant natural gas supply and infrastructure, significant renewable energy potential, and over 1,000 miles of existing hydrogen pipelines, the region already produces one-third of the nation's hydrogen. The HyVelocity Hub is expected to further expand this capacity, while the Gulf's vast CO_2 storage potential supports carbon management strategies essential for low-carbon fuel production. Additionally, the integration of emerging fuels such as hydrogen, RNG, and SNG presents an opportunity to reduce the emissions impact of regional industrial sectors that may otherwise be hard to abate. RNG and SNG, due to their chemical similarity to conventional natural gas, can be more readily injected into existing systems. Hydrogen, while more technically complex, offers significant reduction potential, especially when blended at low levels in the near term.

These emerging fuel pathways are particularly well-suited for specific areas within the region. RNG is ideal for Eastern Arkansas, while H_2 is better aligned with Texas and Louisiana's infrastructure and energy landscape. Texas and Louisiana are the most viable Gulf Coast states to support the adoption of these technologies due to the concentration of available gas infrastructure. Texas and Louisiana would also likely benefit the most from access to affordable H_2 to support ammonia production, petroleum refining, and other industrial markets. For a low adoption scenario of H_2 in the Gulf Coast, increased investments in carbon capture technologies and hubs within the region could support regional, cost-effective emissions reductions.

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

To explore conservative and optimistic low-carbon fuels adoption scenarios, this study assumes average system integration of 5 and 20 vol% (by volume) H_2 and RNG/SNG blends into the Gulf Coast natural gas systems. Repurposing existing infrastructure (particularly pipelines) offers a cost-effective and practical pathway to support this transition. Estimates suggest that converting natural gas pipelines for hydrogen service can cost just 10–35% of new construction. Moreover, using existing rights-of-way can streamline permitting and environmental reviews, accelerate project timelines, and reduce construction-related emissions. However, realizing these opportunities requires coordinated action across technical, regulatory, and economic dimensions. The feasibility of transporting H_2, RNG, and SNG using existing natural gas infrastructure will depend on the characteristics of each pipeline system. Key considerations include material and equipment compatibility, system capacity, and the proximity of fuel production facilities to end users. These technical and economical factors will need to be thoroughly evaluated when repurposing existing assets.

The following recommendations outline key steps to support a safe, efficient, and equitable transition:

Research and Planning

- **Incorporate Fuel Compatibility into Infrastructure Replacement Planning**: As aging infrastructure is replaced, compatibility with emerging fuels should be considered. Selecting materials and designs that can accommodate hydrogen, RNG, and SNG will help avoid future costly retrofits.
- **Conduct System-Specific Assessments of Pipeline Materials and Conditions:** Before repurposing pipelines, detailed assessments evaluating the integrity and suitability of existing infrastructure for alternative fuel applications will help prioritize which segments can be safely and cost-effectively converted. For example, materials such as lower-strength steels and modern polyethylene may be more compatible with hydrogen, while older or high-strength steel pipelines may be more susceptible to hydrogen embrittlement.
- **Perform Integrated Resource Studies:** Comprehensive system-level studies assessing the regional availability and production potential of multiple low-carbon fuels should be conducted to identify optimal fuel blends and deployment strategies tailored to local conditions. Additionally, such assessments can reveal opportunities for co-location of hydrogen, RNG, and SNG facilities to take advantage of shared infrastructure and logistics.

- **Identify End-Use Sectors Tolerant of Hydrogen Blending:** Identifying and engaging with industrial users and power generation facilities that can tolerate alternative fuel blends in their existing gas supply (early adopters) can enable near-term emissions reductions while providing valuable operational data to inform broader deployment. Co-locating production facilities near such industrial activities may also present cost-saving opportunities.
- **Research larger-scale and more efficient electrolyzer, biodigester and/or thermal biomass gasifier technologies.** Strategic investments in these systems could lower fuel production costs and accelerate the regional adoption of H_2 and RNG.

Policies and Landscape Readiness

- **Engage with Regulators on Pipeline Integrity and Cost Recovery:** Collaboration with regulatory agencies is critical to establish standards for fuel-specific risks and clear cost recovery mechanisms to incentivize infrastructure upgrades and reduce the risk burden on necessary financial investments.
- **Foster Public-Private Partnerships:** Public (state and federal government and regulatory bodies) and private (utilities, manufacturers, investors) partnerships can help share risk and resources and align infrastructure investments with broader emissions reductions**.** Additionally, collaboration among pipeline operators, equipment manufacturers, and industrial end-users is essential to accelerate the deployment of emerging fuels.
- **Support Workforce Training and Development:** Investing in workforce training programs on new technologies, safety protocols, and operational practices will ensure that local communities benefit from job creation and economic development tied to the energy transition.

For more information on the case study's background, analysis, and findings, please refer to the full report and appendices available on the RAISE website.

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