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Reliable Affordable Infrastructure
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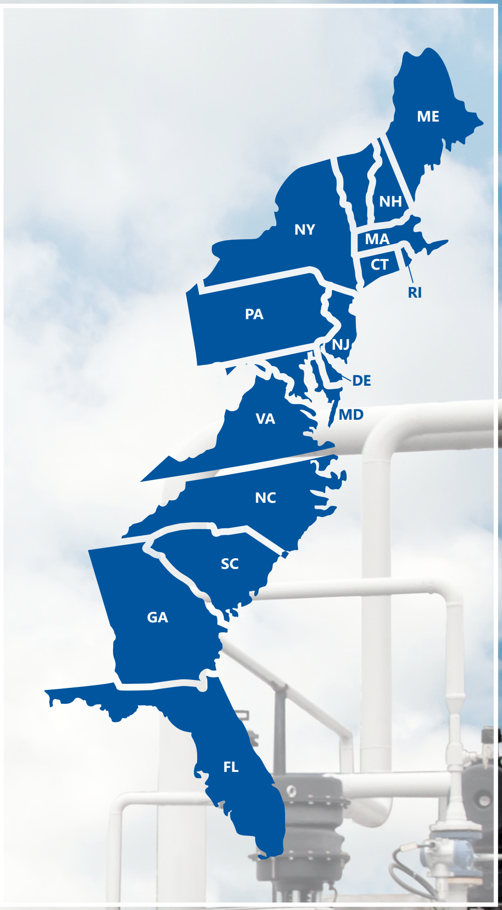
JANUARY 2026



CASE STUDY

Utilizing East Coast Natural Gas Infrastructure

System-Level Pathways for Emerging Fuels,
Infrastructure Modernization, and Regional Flexibility

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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.
Balancing Authorities (BAs)	Responsible for managing the electric grid within a defined geographic area. In the U.S., there are over 60 balancing authorities.
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 East 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 CO2eq/ energy content fuel produced.
Carbon Capture, Utilization, & Storage (CCS)	Recovery of CO2 from industrial or natural sources, and storage into geological or synthetic storage

Carbon Capture, Utilization, & Storage (CCUS)	Recovery of CO2 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 H2, 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 (H2)	Low density fuel, able to be produced from several renewable sources and can be blended into NG systems
Landfill Gas (LFG)	Byproduct of the decomposition of organic materials in landfills. It typically consists of about 50% methane, approximately 50% carbon dioxide, and trace amounts of non-methane organic compounds.
Levelized Cost	Total lifetime cost of building and operating a plant divided by its total lifetime energy production
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. OnLocation is a division of KeyLogic.

Introduction

In the midst of evolving energy infrastructure and a growing emphasis on reliable and secure domestic energy, sustainable emerging fuels such as hydrogen (H2), renewable natural gas (RNG) 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 5 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 focuses on the East Coast region (PADD region 1), which encompasses 17 states: Connecticut, Delaware, Florida, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, North Carolina, Pennsylvania, Rhode Island, South Carolina, Vermont, Virginia, and West Virginia.

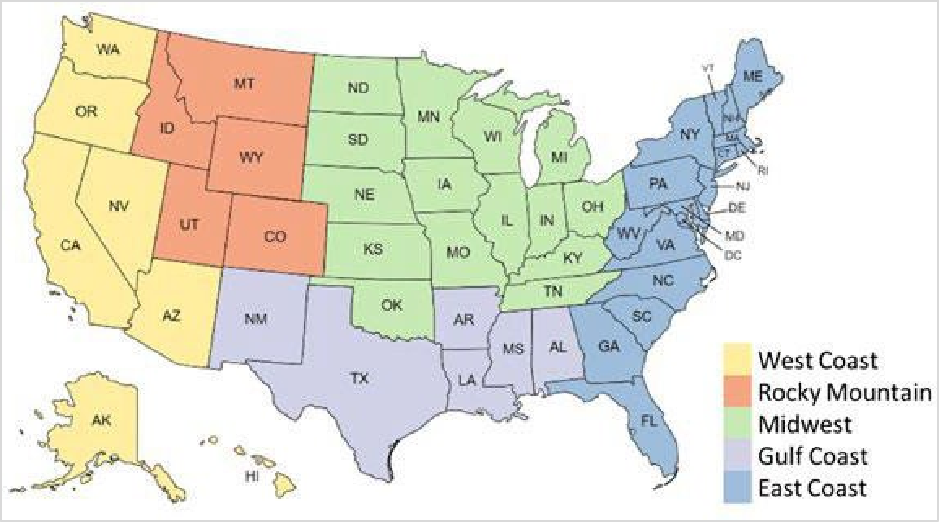

Figure 1. Five U.S. regions, as defined by the Petroleum Administration for Defense Districts (PADD)

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 East 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, H2, 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 East 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 H2 production, three 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 CCS	*without CCS*	*with CCS*	*without CCS*		
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 through H2-8)

- 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 94-96% capture rates
- H2-7: Plasma pyrolysis of natural gas producing H2 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
- RNG-2: Gasification of woody biomass (trees, shrubs, leaves)
- RNG-3: Gasification of agricultural residues
- 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 H2, RNG, and SNG pathways.

2) Lifecycle Analysis (LCA)

The LCA quantifies the environmental impacts across the entire lifecycle 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.

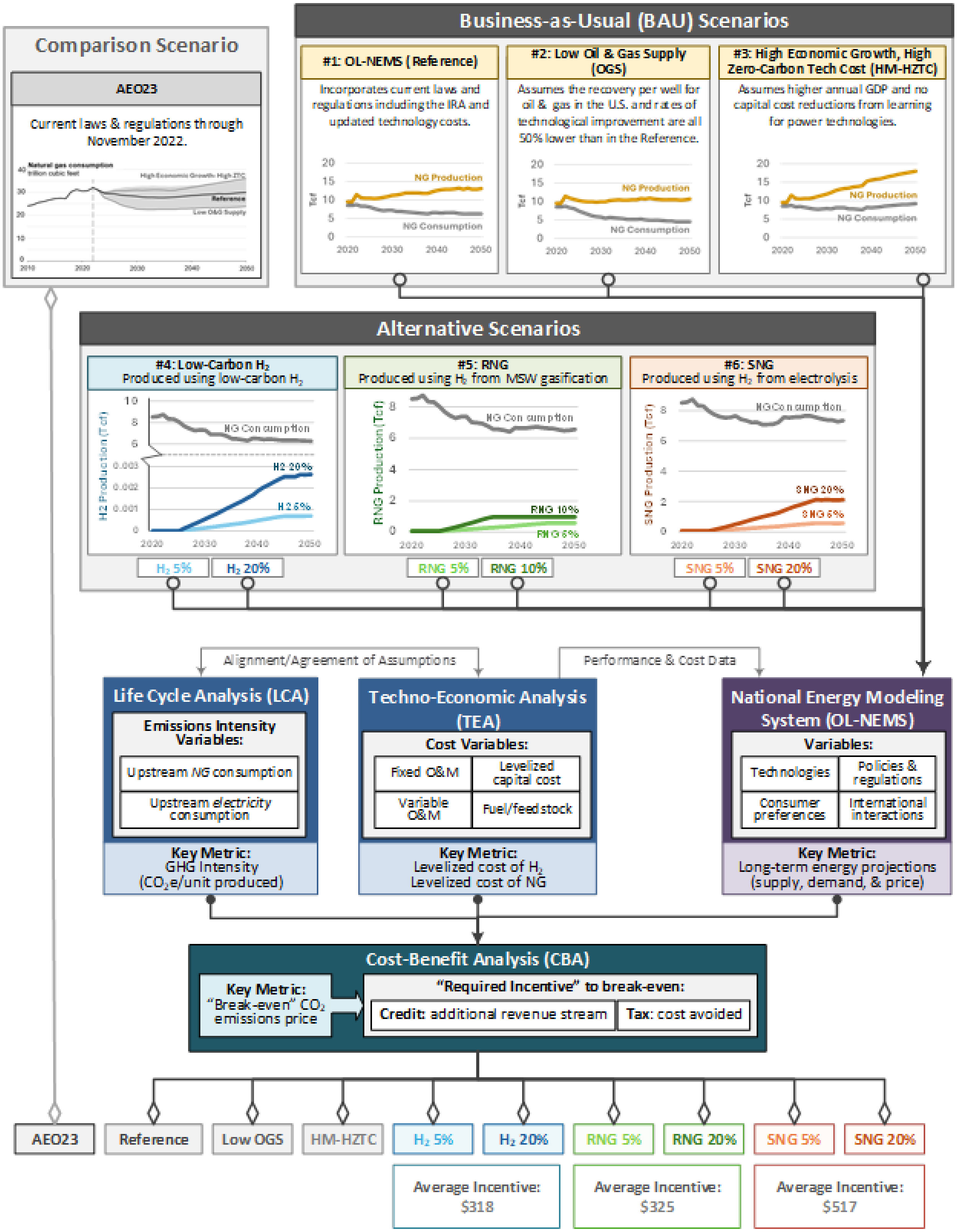

Figure 2. Integrated analysis of cost, emissions, and deployment strategies for H_2, RNG, and SNG pathways.

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, a division of KeyLogic, 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 H2 supply and critical materials demand as shown in **Figure 3**.

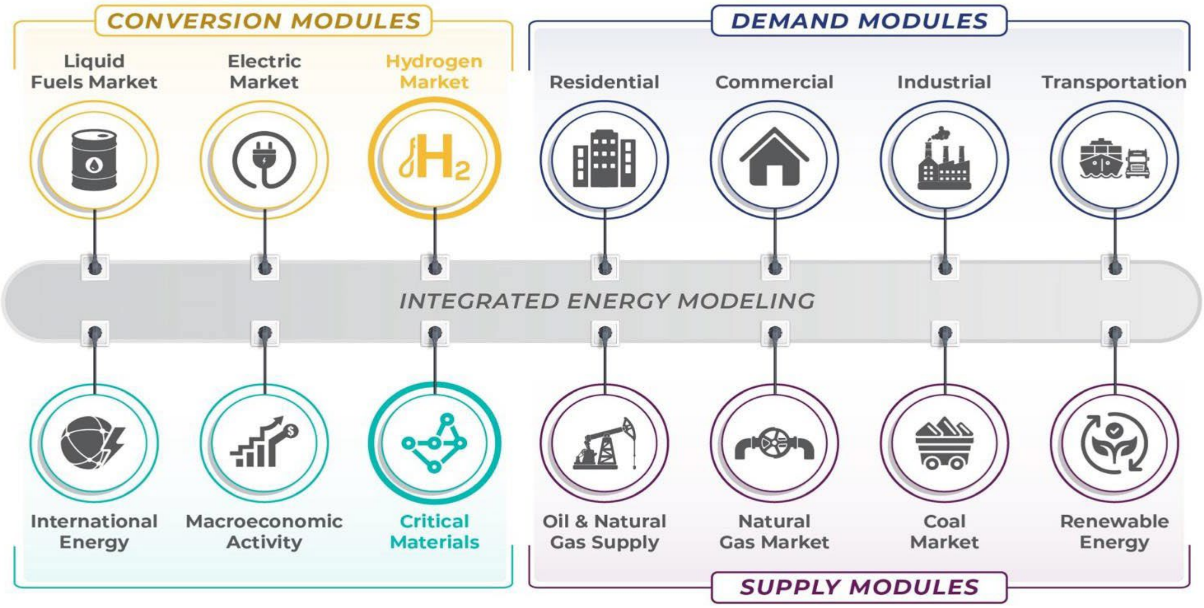

Figure 3. OL-NEMS modules (used with permission from OnLocation)

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 East 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 East 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 East Coast.

Since this case study’s region (PADD’s Region 1 in **Figure 4**) is not directly used in OL-NEMS, module adjustments were made to represent gas and electricity demand and prices in the East Coast region. These region-specific adjustments resolve the regionality differences between OL-NEMS and PADD. **Appendix B** contains information on the adjustments made.

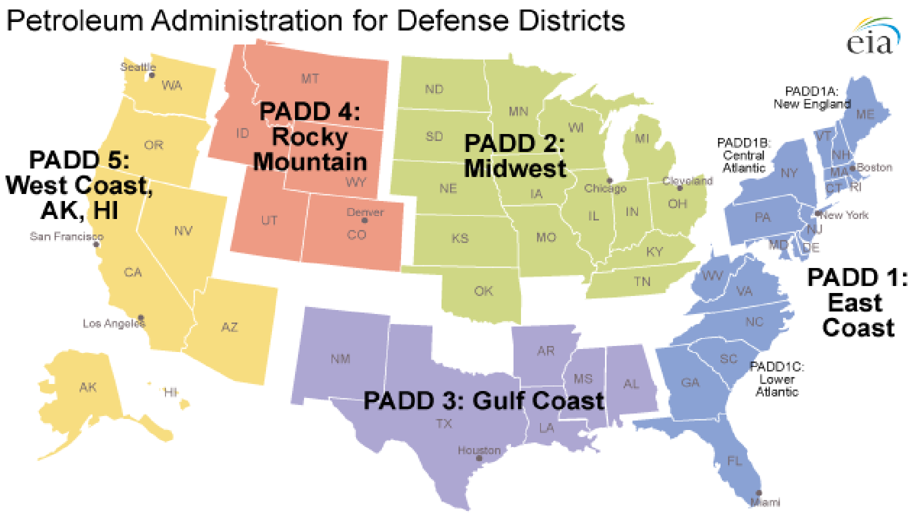

Figure 4. East Coast Case Study region (PADD 1) (Source: EIA)

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 Reference Case	Includes technology cost updates and IRA and other policies implemented since AEO23 was released	**Supportive**
#3: Low Oil/Gas Supply (Low OGS)	Assumes high success of renewables-based technologies adoption	**Supportive**
#4: High Economic Growth-High Zero-Carbon Technology (HM-HZTC)	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.

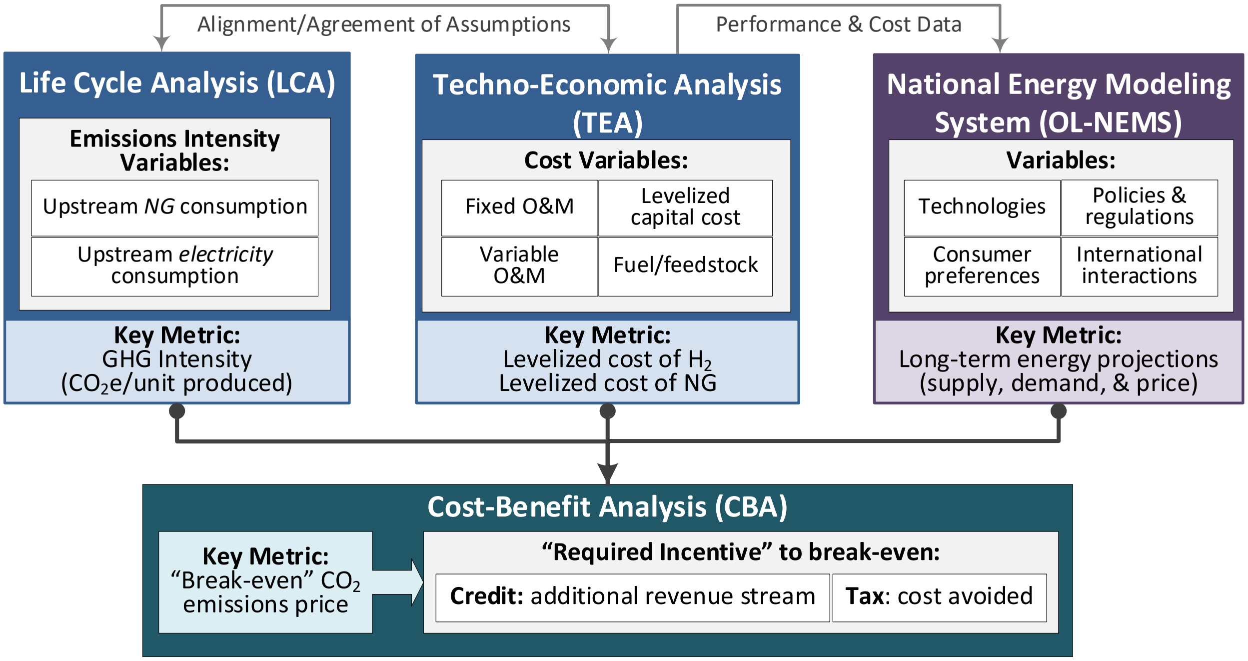

Figure 5. Summary of key TEA, LCA, and resource availability inputs used to inform the cost-benefit analysis.

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(EIA 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 H2-3 to H2-6). 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 carbon intensity of H_2 production pathways across the PADD East Coast region is estimated following DOE's Hydrogen Shot methodology (Lewis et al. 2022a). The study had cradle-to-gate scope; however, RNG-1A represents a true waste boundary case, which begins at the receipt of forest thinning at the production facility. All upstream biomass production and carbon uptake is excluded (Henriksen et al., Release Forthcoming). The emissions from preparing and delivering H_2 to market were estimated, excluding embodied emissions from manufacturing delivery equipment, but including operational emissions.

Two open-source tools were used:

1. **Open Hydrogen Initiative (OHI) Toolkit** provides default parameters for H_2 pathways. For low-carbon cases requiring RNG, upstream natural gas and electricity inputs were modified for state or regional consistency.
2. **OpenLCA Model (developed by NETL)**: serves as a reference for input stream flowrates in OHI, particularly for electricity, natural gas, and water inputs in SNG and RNG pathways.

For alternative SNG cases (SNG-1a–1e), where electrolysis is powered by a single renewable or low-carbon source (e.g., solar, wind, nuclear, hydro, biomass), the full OpenLCA model was not rebuilt for each electricity mix due to complexity. Instead, electricity-related GHG contributions were adjusted externally using literature-based carbon intensities (e.g., 15 gCO_2e/MJ for solar from NREL/Argonne National Laboratory's (ANL) Greenhouse Gases, Regulated emissions, and Energy use in Technologies [GREET], 11 for wind, 12 for nuclear, etc.). These adjusted values were added to non-electricity contributions from the original OpenLCA model.

To estimate upstream carbon intensities for natural gas and electricity in the East Coast region, the NETL/GTI Energy delivery region data was remapped to PADD-defined boundaries using state-level natural gas consumption data from (EIA 2024). This approach assigns each state to either the Northeast or Southeast supply region based on the highest percentage of throughput, applying NETL baseline GHG intensity values of approximately 7.3 g CO_2e/MJ for the Northeast and 10.4 g CO_2e/MJ for the Southeast. Because regional differences are small (within approximately 10% between adjacent regions), this transformation introduces minimal uncertainty. For electricity, state-level upstream impacts were calculated by mapping balancing authorities (BAs) using eGRID 2023 data (Josh Redublo et al., n.d.). Each state's weighted average electricity GHG intensity (kg CO_2e/MWh) was derived from BA-specific generation profiles, using annual net generation as weights. These weighted intensities were then applied to H_2 production pathways by multiplying electricity demand (e.g., 5.97 MJ/kg SNG) and replacing default OHI upstream electricity values with region-specific results. This methodology ensures that upstream emissions reflect actual East Coast grid and gas supply characteristics rather than generic regional averages.

Further details on the LCA modeling approach can be found in **Appendix D**.

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 East 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. These datasets provide the foundation for evaluating the feasibility and scalability of H_2, RNG, and SNG in the East 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 assesses the integration of H_2 and RNG/SNG blends into the East Coast natural gas systems at 5, 10, and 20 vol% (by volume). It is important to note that 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%. Therefore, the target blending rates represent average system-wide targets rather than end-use-specific limits (**Figure 6**).

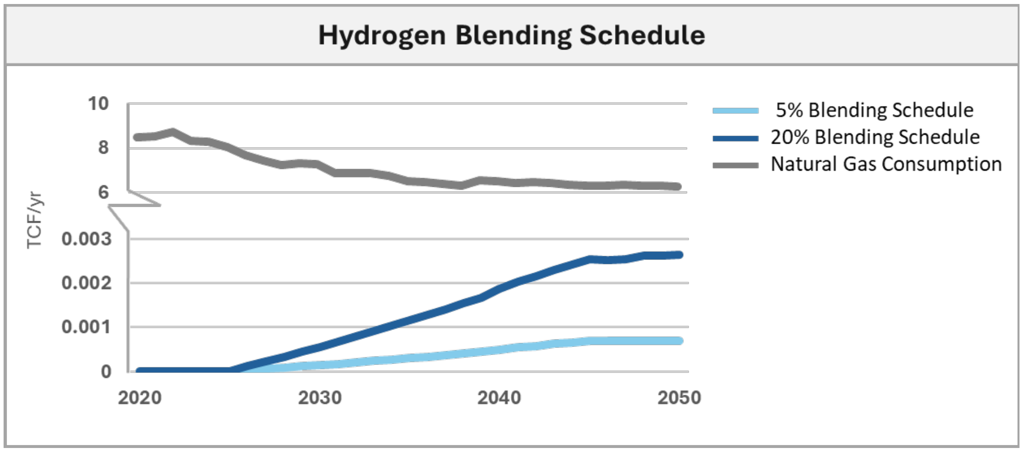

Figure 6. H_2 blending schedule

Although RNG and SNG do not have the same end-use and material compatibility challenges, 10 and 20 vol% blending targets, respectively, are also assumed to align with goals announced by leading natural gas operators. Due to limited feedstock availability in the East Coast, the optimistic RNG scenario is capped at 10 vol% (**Figure 7**).

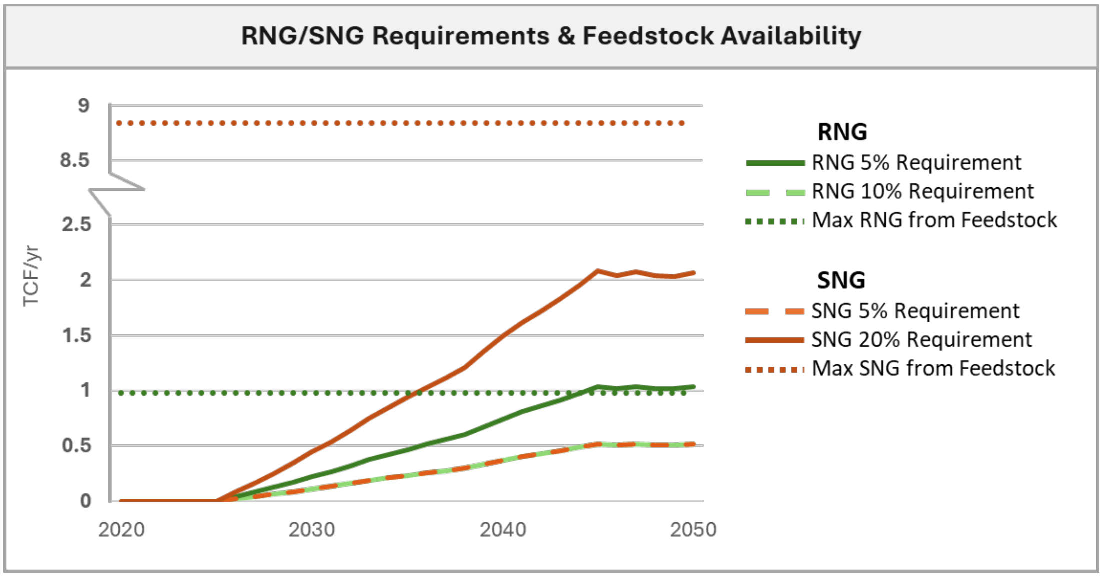

Figure 7. RNG/SNG requirements and feedstock availability

To avoid abrupt shocks to the energy system, the 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%, 0.5 vol%, and 1 vol% per year for the 5 vol%, 10 vol%, and 20 vol% blending cases, respectively, as shown in

Figure 8. Blending is assumed to occur through policy mandates and is not evaluated for economic feasibility.

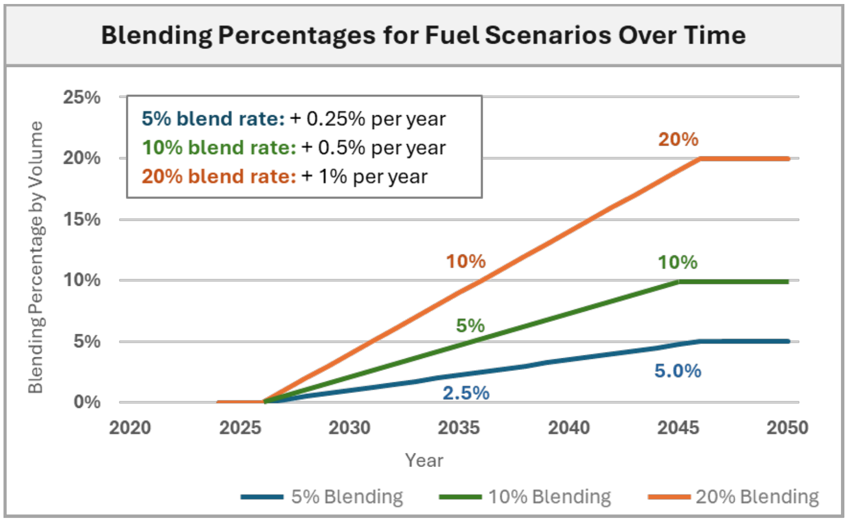

Figure 7. Blending percentages for fuel scenarios over time

OL-NEMS Regional Fuel Case Assumptions

OL NEMS: Low-Carbon H_2

The Low Carbon H_2 case (shown as **LowC H2** in **Appendix H**) 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 H2 are based on the TEA methodology previously discussed. The final price of natural gas to the end use sectors is also impacted by the presence of blended H_2.

OL-NEMS: 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 10 vol% (see discussion above). 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.

Cost and performance data for RNG are derived using the TEA methodology. Additional information on RNG, animal manure, and water resource recovery technologies was sourced from a NYSERDA report (NYSERDA 2022). The final price of natural gas for end-use sectors is also influenced by the inclusion of blended RNG.

OL-NEMS: 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.[1]
- The emissions from each sector are also updated based on the CO_2 captured to produce SNG, lowering the emissions further.

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[1] NEMS does not perform a full LCA. Instead, it only accounts for direct emissions from fuel combustion. Certain fuels are classified as zero-emission when the emissions they generate replace emissions that have already been captured. In the case of SNG, the CO_2 released during combustion offsets the CO_2 captured and utilized in its production. This substitution is why SNG is considered zero-emissions within the OL-NEMS framework.

The cost and performance data for SNG are 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.

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

Natural Gas Demand

The majority of natural gas consumption in the East coast is driven by electric power generation, particularly in Pennsylvania, Florida, and New York. **Figure 9** shows the percentage of fuel consumption by sector represented by natural gas consumption across states.

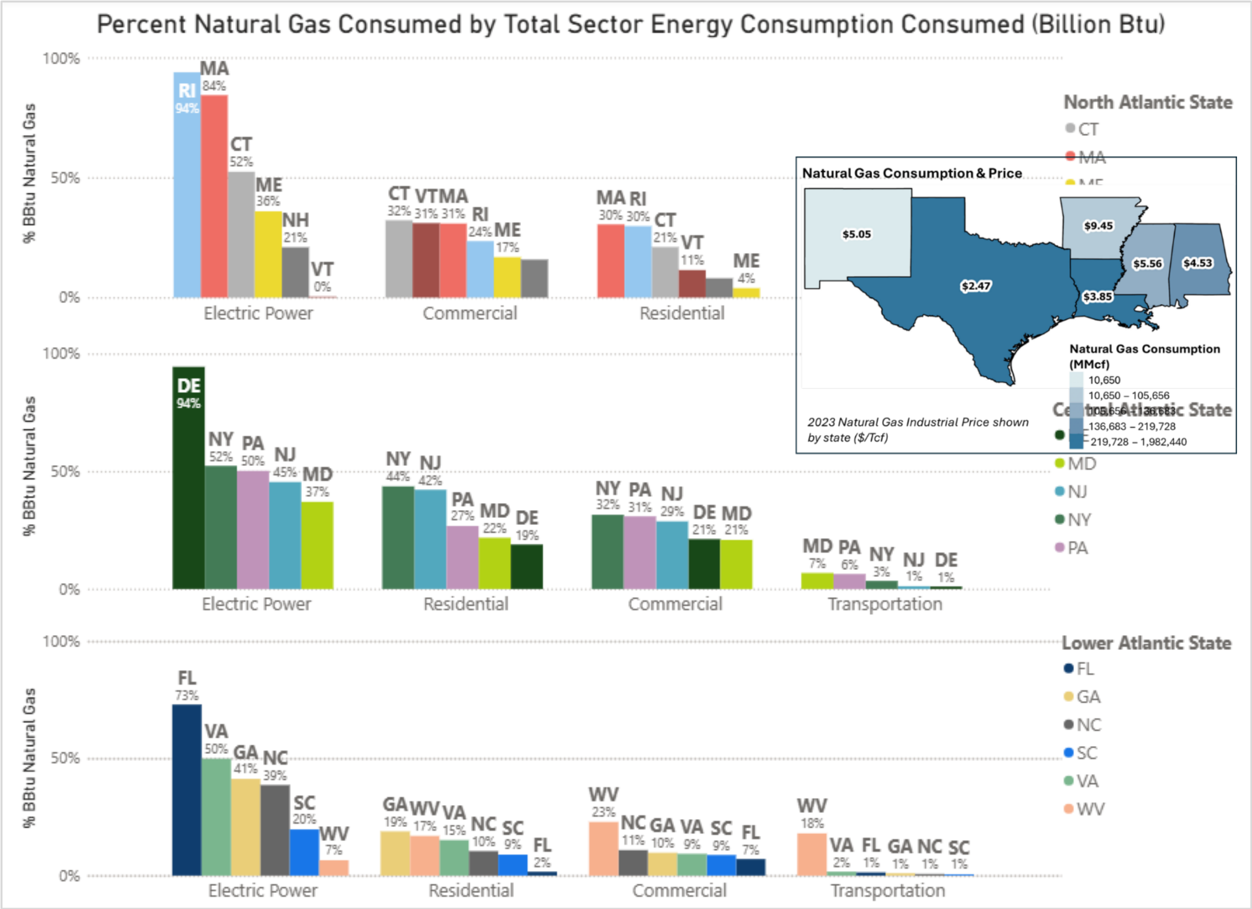


Figure 9. Percent of total sector energy consumption associated with natural gas (billion Btu, PADD subregion)

Each East coast subregion exhibits different sector-level reliance on natural gas, with states such as Florida, Georgia, North Carolina, and Virginia, demonstrating higher reliance on natural gas for electricity generation (**Figure 10**). The strongest similarities in natural gas reliance are observed for the transportation and commercial sectors. However, the New England region stands out for its higher reliance on natural gas among commercial end users compared to residential end users. While power generation remains the dominant sector for natural gas consumption overall, the degree of reliance varies by state.

Natural gas deliveries are most substantial in Pennsylvania, Florida, New York, and Georgia. In general, the highest natural gas prices are associated with residential end use, followed by commercial and industrial sectors. However, each state and sector experience different prices. For instance, Maryland demonstrated similar commercial and residential natural gas prices between 2019 and 2024, whereas Georgia experienced a roughly two-fold difference between commercial and residential natural gas prices between 2023 and 2024.

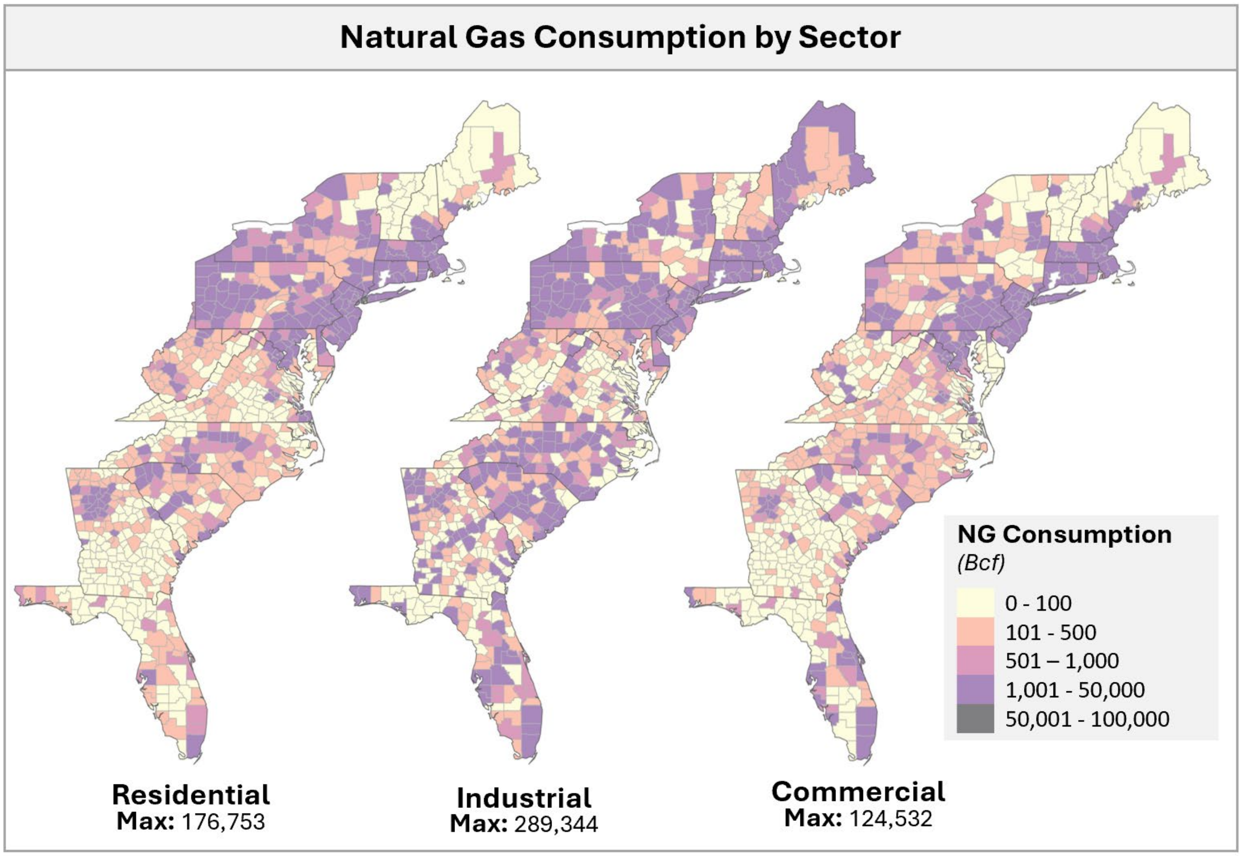


Figure 10. Natural gas consumption by sector and county

H_2 Demand

Figure 11 illustrates current and projected H_2 demand for the East Coast region, based on data from Evolved Energy Research's 2024 U.S. Annual Decarbonization Perspective Baseline Scenario (Evolved Energy Research 2025). At present, the majority of H_2 demand is concentrated in petroleum refining and ammonia production, with the Lower Atlantic subregion accounting for most of this demand. Additionally, though smaller, contributions come from transportation and other industrial applications.

Looking ahead to 2050, the demand profile is expected to diversify. In addition to continued strong demand from petroleum refineries and ammonia production, new demand drivers will emerge in sectors such as electric fuels, iron and steel manufacturing, and power generation. In particular, the Central Atlantic is anticipated to experience a notable increase in H_2 demand, complementing growth in the Lower Atlantic.

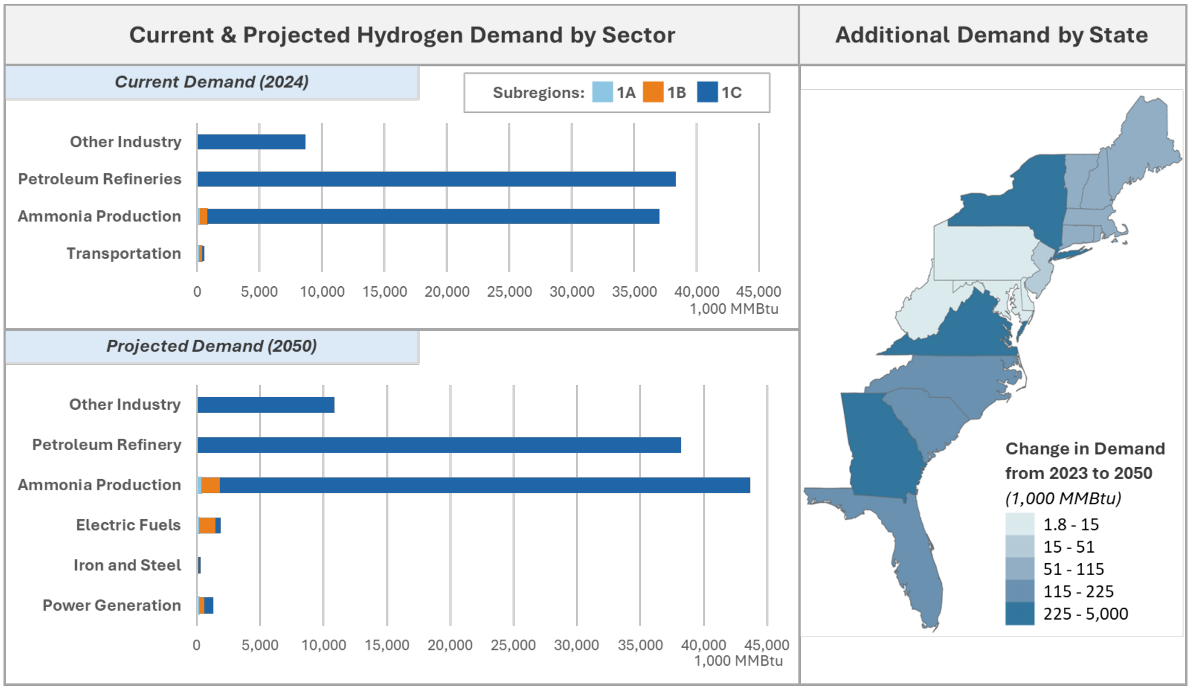


Figure 11. Current and projected H_2 demand by sector in the East Coast

Among individual states, the largest projected increases occur in Virginia, Georgia, New York, North Carolina, South Carolina, and Florida, listed in descending order of expected growth.

OL-NEMS Estimated Future End-Use Demand

As a comparison to the demand estimates shared in the previous section, the regional analyses present natural gas demand and prices over a range of economic scenarios which impact the overall adoption rates of H_2, RNG and SNG. For instance, the AEO23 Reference case assumes coal power generation and coal plant capacity remains present in 2050, unlike in the other scenarios where they are nearly phased out. Other energy trends in this case remain more aligned with historical projections rather than the shifts observed in the alternative cases.

In contrast, the Low OGS case estimates the total emissions in 2035 to be lowest due to reduced energy availability and slower macroeconomic growth. LNG exports and total natural gas consumption are also at their lowest levels. Natural gas production from shale does not increase, unlike in other scenarios. Henry Hub spot prices and delivered natural gas prices are higher in this case, leading to increased energy costs.

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 conventional natural gas. Across the AEO23, Low OGS, and Reference cases, sector-level H_2 demand remains negligible from the present through 2050. Consequently, the model primarily considers elective adoption of select H_2 scenarios based on a predefined natural gas system blend rate.

Blended Natural Gas Demand

Figure 12 visualizes projected blended natural gas demand findings from 2020 to 2050 by sector and economic scenario. Residential and commercial demand remains largely stable from 2035 to 2050 across all scenarios, contrasting with historical residential natural gas trends. Total blended NG consumption is lowest in the Low OGS case and highest in HM-HZTC and SNG scenarios, driven primarily by power sector demand.

In the LowC H2 cases, elevated H_2 demand is offset by reduced industrial natural gas use as H_2 displaces natural gas as a fuel source.

In the SNG blending cases, particularly the SNG 20 vol% case, power generation and capacity expand significantly, primarily in renewables, aligning with other scenarios except AEO23 and Low OGS by 2035. Coal power is nearly eliminated, and natural gas demand in the power sector is lower in 2035, leading to slightly lower natural gas prices before they rise in later years. 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. In the 20% case, additional SNG is needed to meet increased natural gas demand. However, the price of SNG rises once the 45Q credits expire, reaching >$100/MMBtu (2023$) by 2040.

For RNG blending cases, RNG production scales with blending levels but remains costlier than other H_2 production pathways. No scenario includes H_2 production from RNG.

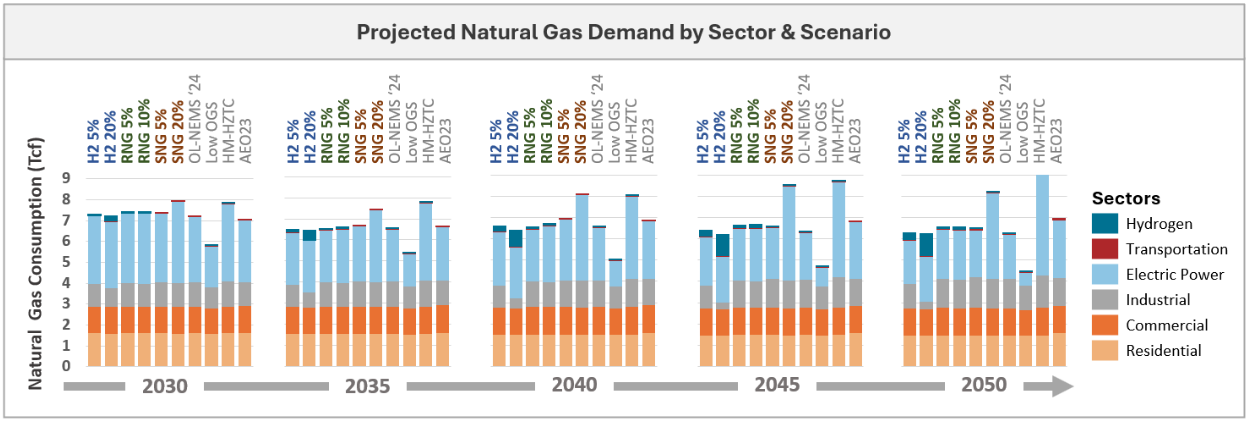


Figure 8. Natural gas consumption by sector and scenario

H_2 Demand – Regional Findings

In this section, H_2 demand projections from 2030 to 2050, based on OL-NEMS findings, are summarized. H_2 demand was modeled using EIA AEO23 scenario assumptions, which incorporate existing demand estimates and predefined blending assumptions.

Given the importance of H_2 as a feedstock for SNG production, the expansion of SNG blending is expected to require the most significant quantities of unblended H_2. The results indicate minimal growth in pure H_2 demand within the industrial sector; instead, demand increases primarily occur through H_2 blends.

Figure 13 summarizes anticipated regional H_2 demand for blending into natural gas systems and highlights differences in anticipated H2 demand across the cases. The LowC H2 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, and prices rise above $25/MMBtu (2023$) in 2035.

In contrast, non-blending scenarios show negligible H_2 demand because the model optimizes for cost, and H_2 remains more expensive than natural gas. However, as discussed in the **Estimated End-Use Demand in the Region (H_2 Demand)** section, regional H_2 demand is expected to grow between now and 2050, particularly in Virginia, Georgia, New York, North Carolina, South Carolina, and Florida. If incentives are available to lower production costs, OL-NEMS may reveal increased H_2 demand.

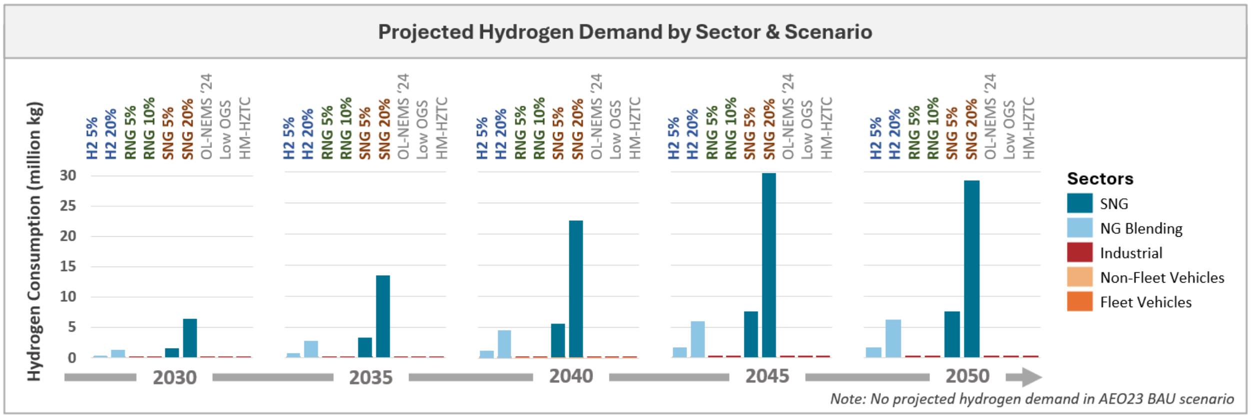


Figure 9. Projected H_2 demand by sector and scenario

Resource Availability in the Region

The feasibility of the H_2, RNG, SNG pathways is highly dependent on positioning production in vicinity of biomass, CO_2 sources, renewable electricity generation, and natural gas delivery infrastructure. With the economic analysis and resource availability findings in the East Coast, the study finds multiple exceptions in which the lowest cost case for H_2 and RNG are not necessarily the optimal option to produce the fuel in a specific state.

Natural Gas Reserves

The viability of H_2 production via NG will be dependent on reliable and affordable access to natural gas. The most extensive natural gas reserves in the region are associated with geological formations in the northeast, namely from the Marcellus Shale formation, located in Pennsylvania, New York and Virginia, and Maryland (**Figure 14**).

The New England subregion does not have active natural gas reserves and relies on natural gas imported from Marcellus Shale formation located in West Virginia, Ohio, and West Virginia and production in Canada. In 2024, Canada supplied 31,786 Mcf natural gas to Maine, and 236,427 Mcf to New York via international natural gas transmission pipelines (EIA 2025b).

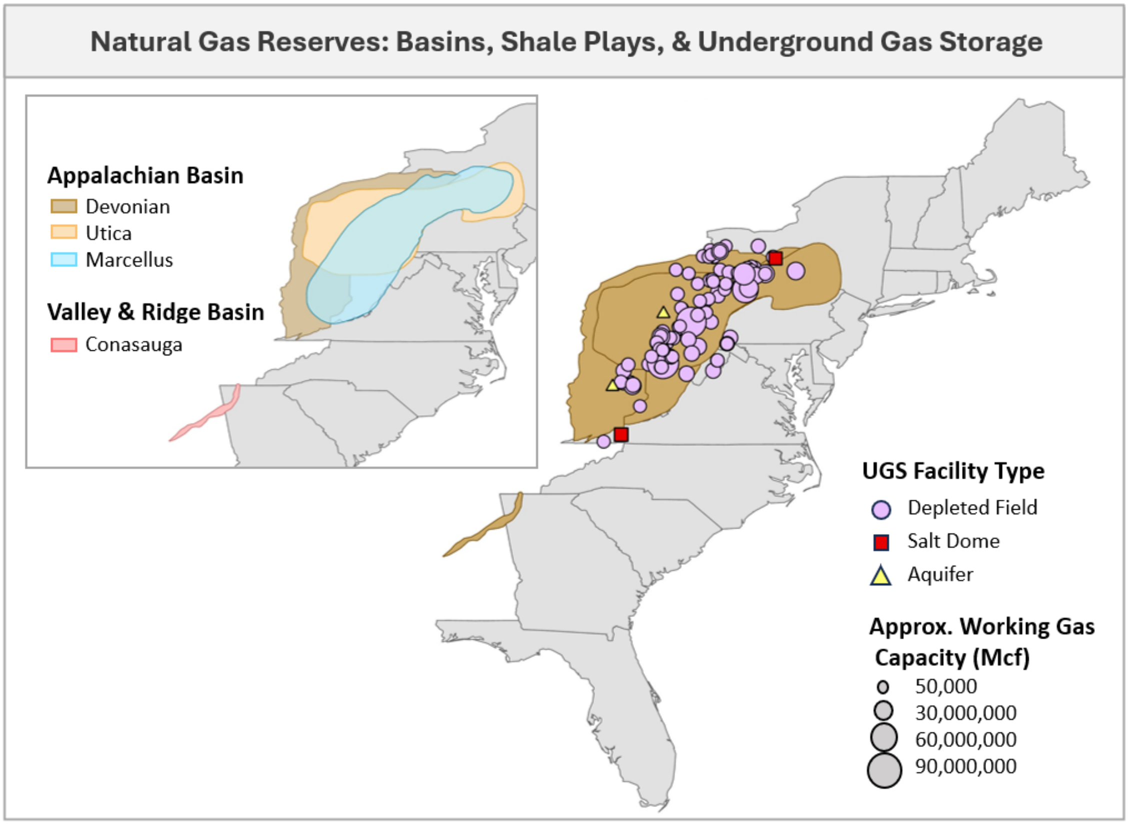
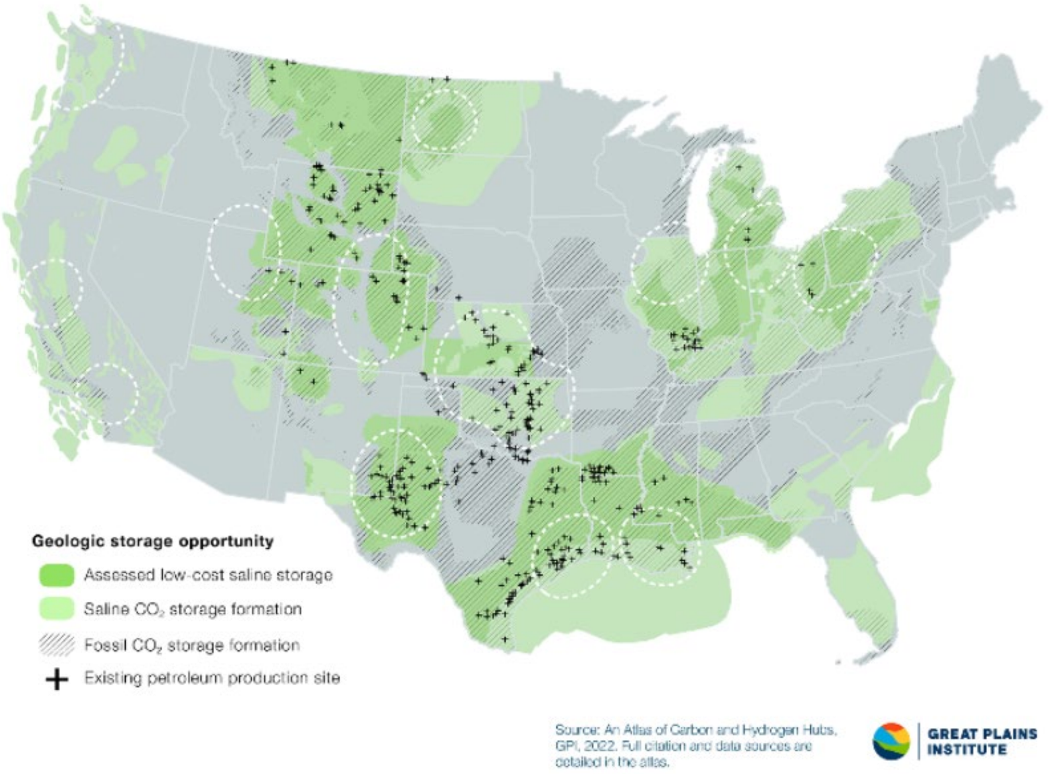


Figure 104. Natural gas reserves in the East Coast

Similar to New England, the Central Atlantic subregion relies on natural gas imported from Marcellus Shale formation located in Pennsylvania, Ohio, and West Virginia and production in Canada. In 2024, Pennsylvania, second to Texas produced the most natural gas in the U.S. The Lower Atlantic states both rely on natural gas from the Marcellus shale as well as from the Permian and Haynesville Basins located in the Gulf Coast.

CO_2 Storage Availability

Byproduct CO_2 from H_2 produced via NG SMR or ATR w/ CCS will require CO_2 storage. Instate CO_2 storage is not necessarily a requirement for the viability of NG SMR or NG ATR w/CCS, as there are current examples of projects which transport CO_2 from industrial sites to nearby storage sites. However, states with available underground storage are better positioned to scale CCS dependent fuel pathways. **Figure 15** below shows geologic storage opportunities for CO_2 occurring in Pennsylvania, New York, West Virginia, South Carolina, Georgia, and Florida. A combination of saline and fossil CO_2 storage opportunities resources are estimated in various East Coast states.



Source: An Atlas of Carbon and Hydrogen Hubs, GPI, 2022. Full citation and data sources are detailed in the atlas.

Figure 11. Geologic storage opportunities in the U.S. (Great Plains Inst.)

Solar and Wind Resources

Figure 16 summarizes the wind and solar resources in the East Coast, along with utility-scale (1 MW and above) wind and solar facilities. There are a range of known capacity factors for solar and wind generation facilities in the East Coast. According to 2023 EIA reported facility data, capacity factors for photovoltaic facilities can range from 15.2 to 22.8, while wind facility capacity factors range from 20.4 to 44.7 among the East Coast states. Along with regional solar irradiance and wind potentials, facility capacity factors are also dependent on other state-independent factors such as system design and materials.

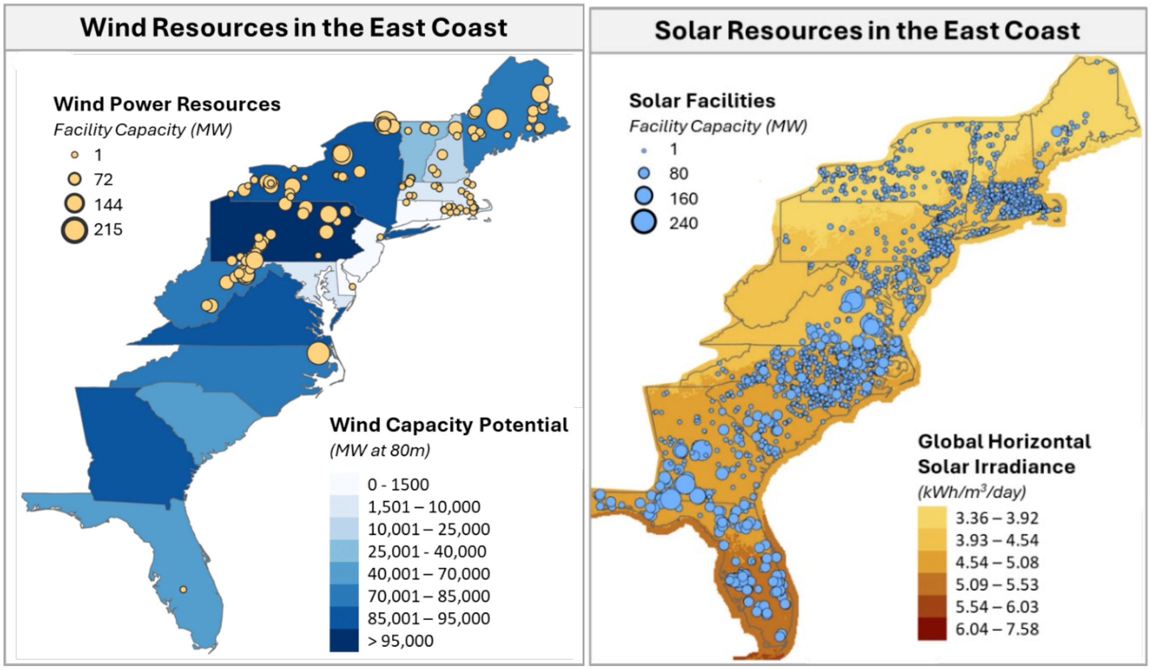


Figure 12. Wind and solar resources in the East Coast

Clusters of wind generation facilities are located in the New England and Central Atlantic regions (mainly Pennsylvania, New York, and Maine), whereas the Lower Atlantic largely lacks wind generation facilities. There are currently untapped wind resources in the Lower Altantic, particularly in Georgia and South Carolina. Alternatively, the Lower Atlantic lead in solar power generation, with clusters of larger facilities operated in Florida, Virginia, and North Carolina. Due to the distribution of current wind and solar power generation, the analyses also consider solar/wind electricity mix for the purpose of producing electrolytic H_2 (H2-8a/b).

Nuclear and Hydro Resources

Current utility-scale power generation via nuclear and hydroelectric facilities, major waterways and example hydroelectric facility capacity factors are summarized below in **Figure 17**.

Hydroelectric facilities are expected to be one of the most resource-constrained renewable electricity generation pathways over time. Utility scale hydroelectric facilities exist in each East Coast subregion, with greater clustering in New York, Vermont, Maine, and New Hampshire. Nuclear power generation has greater prevalence in the Central Atlantic and Lower Atlantic states.

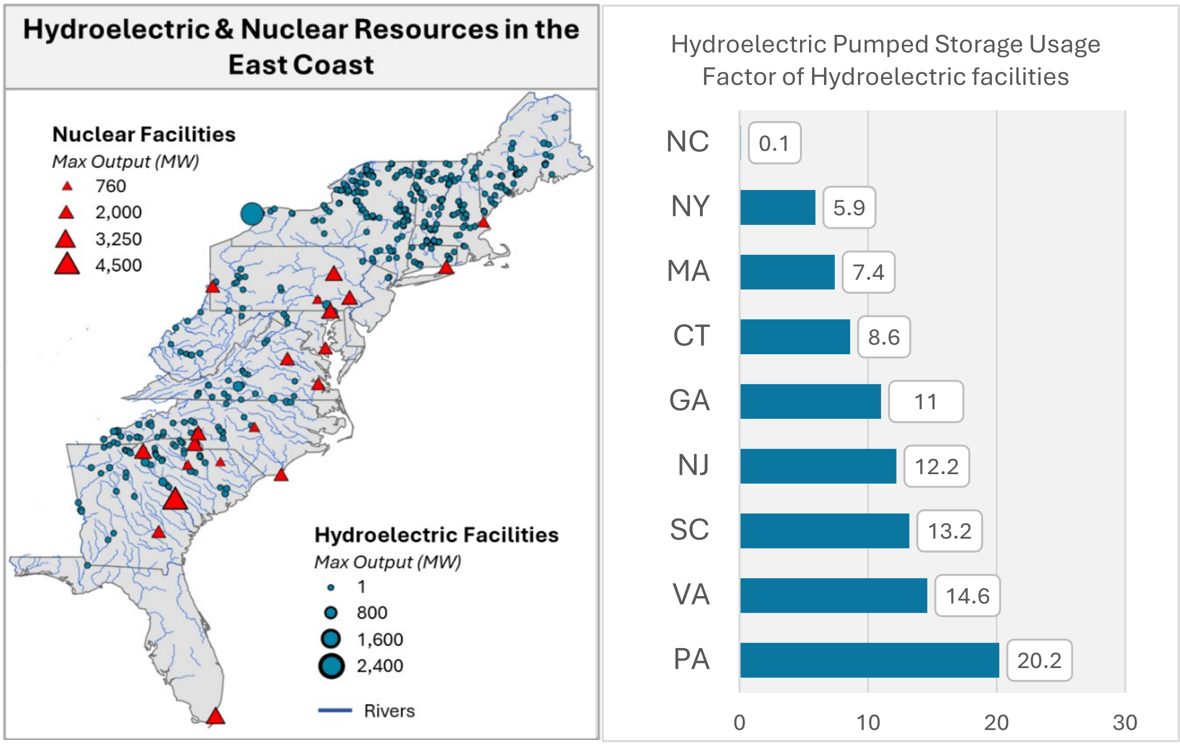


Figure 13. Hydro and nuclear resources in the East Coast

While example hydroelectric facilities in Pennsylvania, Virginia, and South Carolina have higher hydroelectric pumped storage usage factors, New York has a higher number of facilities, as well as larger facilities. These hydroelectric storage usage factors may also change over time. Various factors contribute to the future potential of hydroelectricity in the East Coast states. Thus, this study constrains discussion on the opportunities for hydropower to the current generation rates in each East Coast state.

Existing solar, wind, nuclear and hydroelectric resources provide a near term understanding of electrolytic H_2 production poential in the East Coast. While not considered in this study, offshore wind potential may provide additional opportunities for electrolysis produced in the East Coast states in the future.

Agricultural Residues & Forest Residues

The East Coast has significant biomass resources, largely attributable to its extensive geographic footprint (**Figure 18**). Spanning 17 states along the entire eastern seaboard and encompassing substantial inland areas, this region ranks second nationally in total biomass waste availability. Agricultural activity is robust in the southern states, gradually tapering off as the climate becomes cooler toward the north. Notably, New York and Pennsylvania stand out as high-agriculture outliers despite their northern location. In addition to crop residues, forest resources are a dominant contributor to biomass potential across the East Coast. Extensive forested areas, including those in the southern states and the Appalachian region, provide a steady supply of forest residues. Several counties in Maine and Pennsylvania produce over 1 million dry tons annually, with additional concentrated pockets in the Carolinas. This diverse and plentiful biomass base positions the East Coast as a strategic leader in renewable energy development.

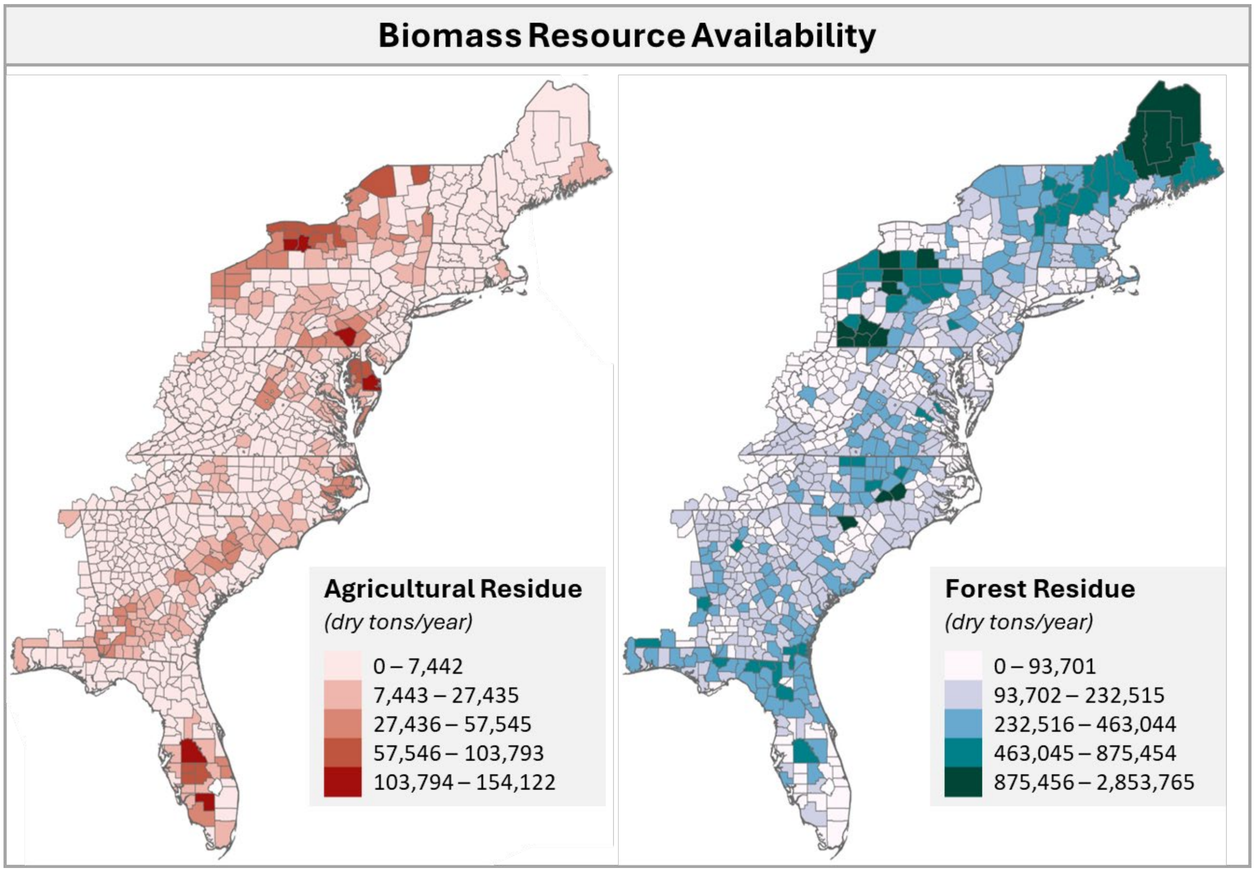


Figure 14. East Coast agricultural and forest residue availability

Municipal Solid Waste & Landfill Gas

MSW availability in the East Coast region is high, driven by the concentration of some of the nation’s largest and most densely populated metropolitan areas (**Figure 19**). This includes major urban centers across Florida and New York, as well as Pittsburgh and

Philadelphia in Pennsylvania, Boston in Massachusetts, and numerous others. Notably, the District of Columbia alone generates more than 300,000 tons of MSW annually, underscoring the scale of waste production in this area.

LFG data from the EPA further reinforce this observation. The East Coast region exhibits the highest potential for LFG recovery in the U.S. This is primarily attributable to its expansive geographic coverage combined with the presence of several highly urbanized and densely populated states, including Florida, Pennsylvania, New Jersey, and New York. Additional contributions come from rapidly growing areas such as Eastern Virginia and Central North Carolina. Collectively, these factors create a significant opportunity for energy recovery and GHG mitigation through enhanced LFG utilization in 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.

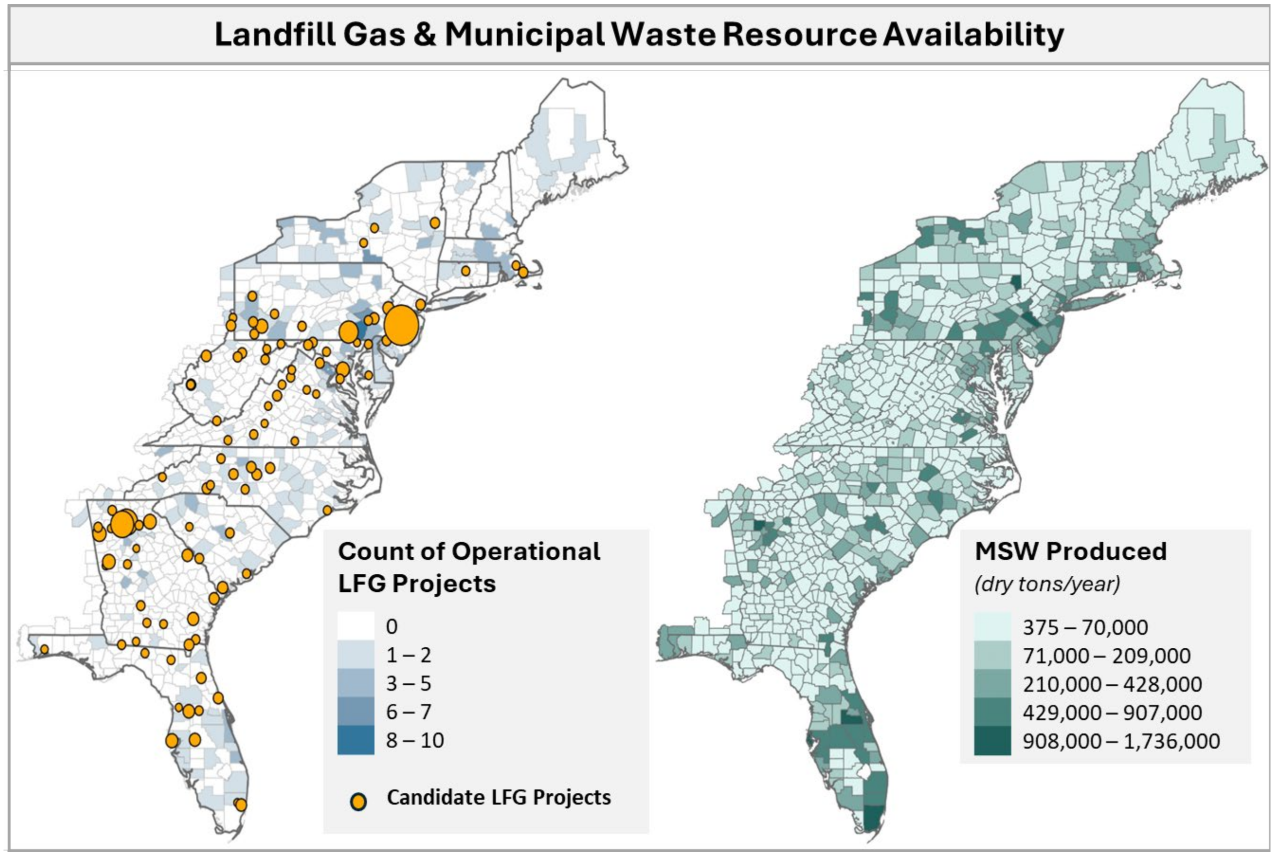


Figure 15. East Coast LFG projects (active and candidates) by county and MSW production

Existing Landfill Gas Energy Projects

As of 2024, the EPA LMOP LFG Energy project database reports 28 operational LFG projects which produce RNG, and 194 LFG projects which produce electricity in the East Coast states (US EPA 2024). The prospects for facility conversions to upgrade LFG to electricity projects to produce RNG will be dependent on facility sizes and local end use demand for pipeline gas. One example of this facility conversion can be seen with the Illinois Winnebago LFG conversion project which roughly doubled energy output when converting to produce RNG from previously producing electricity onsite (Pipeline & Gas Journal 2025).

Wastewater

For comparison purposes, this study includes a separate reference case evaluating RNG production from wastewater at the regional level. The economic viability of producing RNG via anaerobic digestion at municipal wastewater treatment plants (WWTPs) depends largely on the facility's location and size, both of which correlate with the population served. Larger WWTPs are concentrated along the East Coast, particularly in the Northeast (**Figure 20**).

Figure 16. Number of facilities with wastewater biogas systems (ANL, 2022)

In a 2022 ANL study, RNG production via wastewater biosolids is considered for facilities which process at least 5 Mgd. (million gallons per day) (Ha and Gutenberger 2022). According to EPA reported WWTP data, most East Coast states have at least one existing WWTP that satisfies this requirement (U.S. EPA 2025).

CO₂ Supply for SNG

Figure 21 summarizes the CO_2 point sources evaluated for SNG production, categorized by state. Across the region, natural gas-fired power plants often represent the most common and significant source of CO_2 flue gas considered in this study, totaling approximately 484.8 million tons per year.

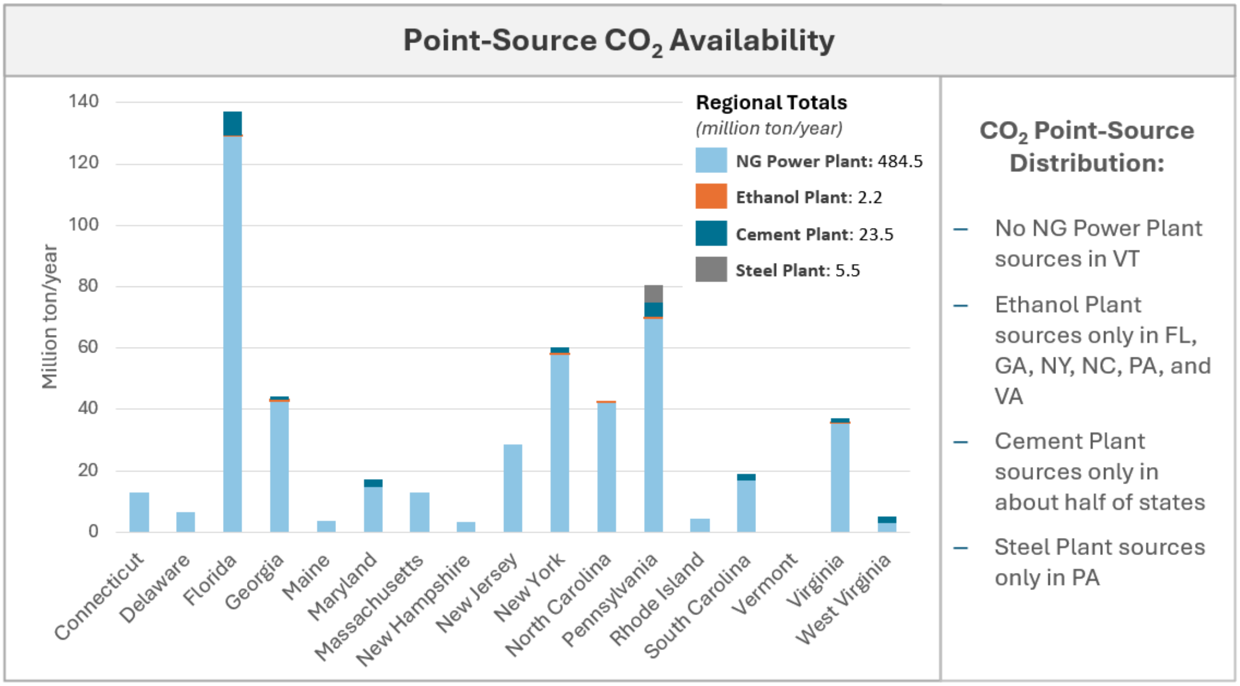


Figure 17. Point source power and industrial CO2 availability in the East Coast

Cement manufacturing facilities constitute the second-largest potential source; however, their contribution is substantially smaller, at 23.4 million tons per year.

TEA and LCA Findings Overview

The technoeconomic analysis and lifecycle analysis output two parameters which indicate the associated costs and emissions reduction potential of each considered fuel pathway: levelized cost and carbon intensity. These metrics respectively indicate the economic viability and emissions reduction potential of the pathways under consideration. **Figure 22** presents a state-level comparison of levelized costs by H_2 fuel case alongside their associated carbon intensities.

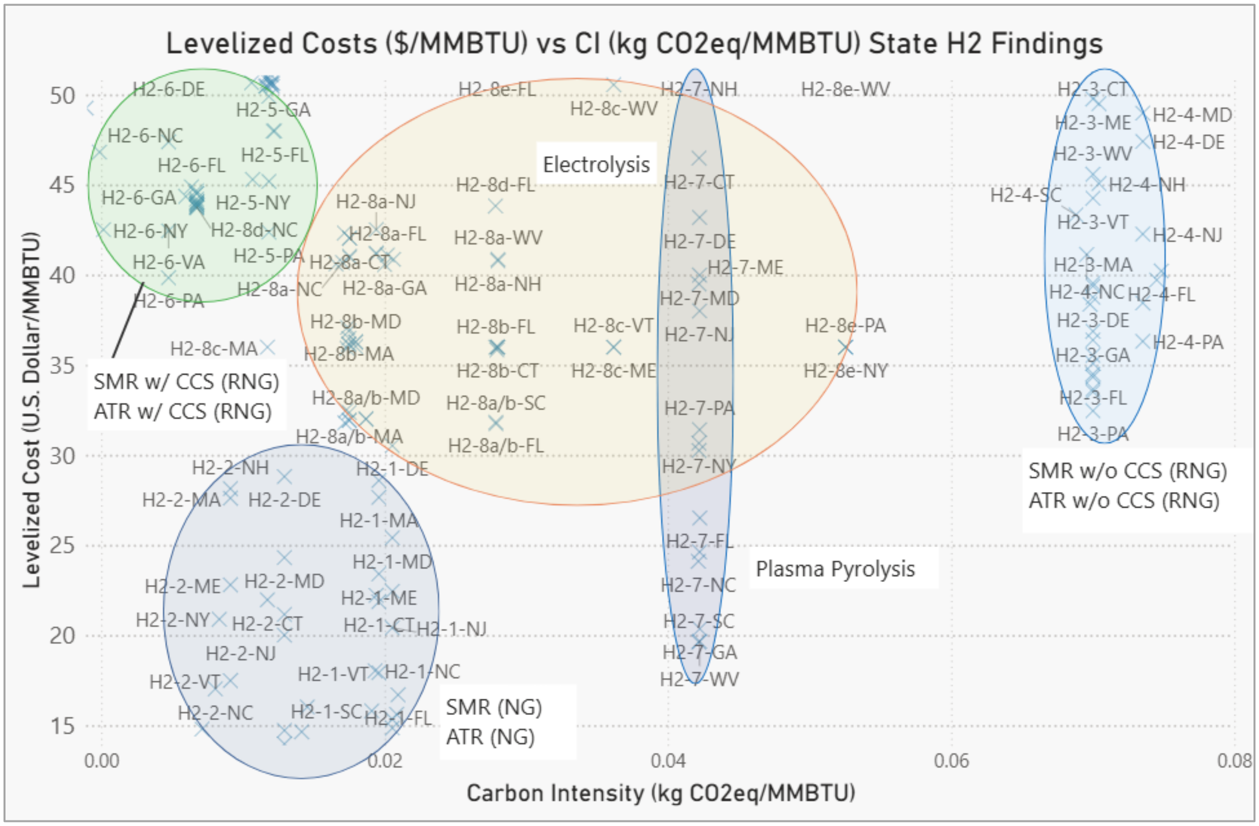


Figure 18. H_2 levelized costs vs. carbon intensities by state

The analysis reveals notable regional variability in estimated production costs across the different fuel pathways, with particularly pronounced differences for Plasma Pyrolysis (H2-7), SMR without CCS (H2-3), and Electrolysis (H2-8). In certain states, H_2 produced via natural gas plasma pyrolysis achieves levelized costs below $35/MMBTU, placing it within the cost range observed for SMR with CCS and ATR with CCS across several East Coast states. Among the ATR and SMR pathways evaluated, the integration of CCS consistently delivers greater emissions reductions and lower costs compared to substituting NG with RNG as the process fuel.

A similar comparison for the RNG and SNG cases is visualized in **Figure 23** for all East Coast states (note that some state cases are not labeled due to similar levelized costs). This figure highlights the wide cost variability for RNG produced via upgraded LFG, as well as the relatively similar cost ranges observed for SNG pathways utilizing different CO_2 capture sources. RNG produced through agricultural and forest residue gasification also exhibits comparable cost profiles. Specifically, RNG derived from upgraded LFG demonstrates levelized costs ranging from $33 to $58/MMBTU, underscoring the influence of feedstock and regional factors on economic performance.

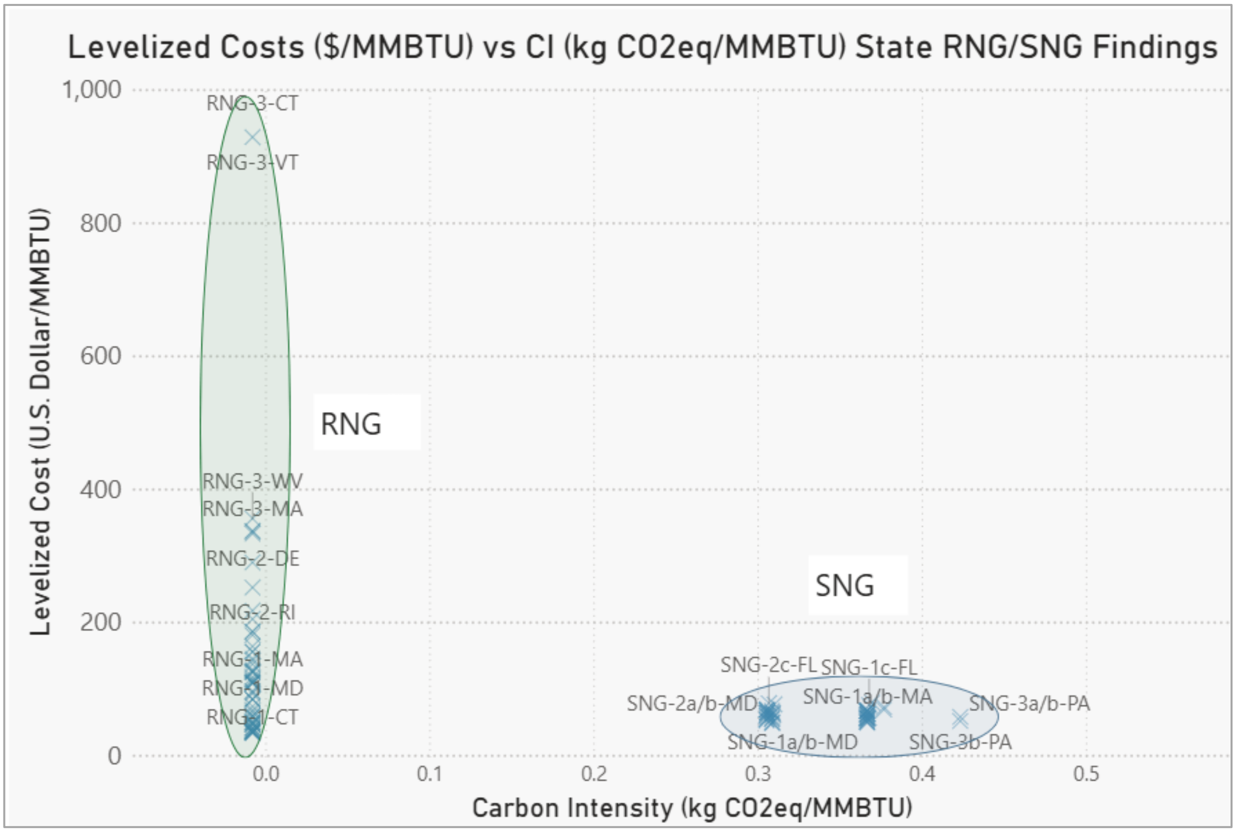


Figure 19. RNG/SNG levelized costs vs. carbon intensities by state

In general, the SNG fuel cases considered are found to require higher incentives due to less competitive emission reductions compared to the RNG cases. However, some RNG production pathways, namely RNG via agricultural residue and forest residue digestion, are found to have especially higher levelized costs ($65 to $2500/MMBTU), depending on the specific state.

Required Incentives Overview

The TEA and LCA required incentive calculation findings show generally reduced incentives when excluding carbon intensities. Across East Coast states, it is the general trend that electrolysis, RNG ATR w/ CCS, and RNG SMR w/ CCS demonstrate lower LCA required incentives compared to calculated TEA incentives. The most significant differences between LCA and TEA required incentives are for RNG ATR w/ CCS, yielding required incentive reductions from \$63-200/CO_2 abated when CI is structured into the required incentive.

As for the RNG and SNG pathways, the LCA incentives for MSW digestion are lower than the TEA incentives by \$138-1261/ton CO_2 Abated, depending on the state. Thus, the following section presents both the LCA and TEA incentive findings at the state level.

State-Level Findings

The state-level findings incorporate consideration of available resources, state-specific costs for electricity, natural gas, CO_2 T&S, and labor rates. The incentives described in this section represent the economic offset required for the given fuel to reach cost parity with natural gas. 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 state summaries note the fuel pathways with the lowest estimated incentives required.

PADD 1a: New England

Maine, Vermont, New Hampshire, Connecticut, Rhode Island, Massachusetts

Case Study Analysis: New England State Price Inputs

Figure 24 below summarizes New England state level costs for natural gas, electricity, transportation and storage of CO_2, and average labor rates, each of which contribute to the fuel case technoeconomic findings.

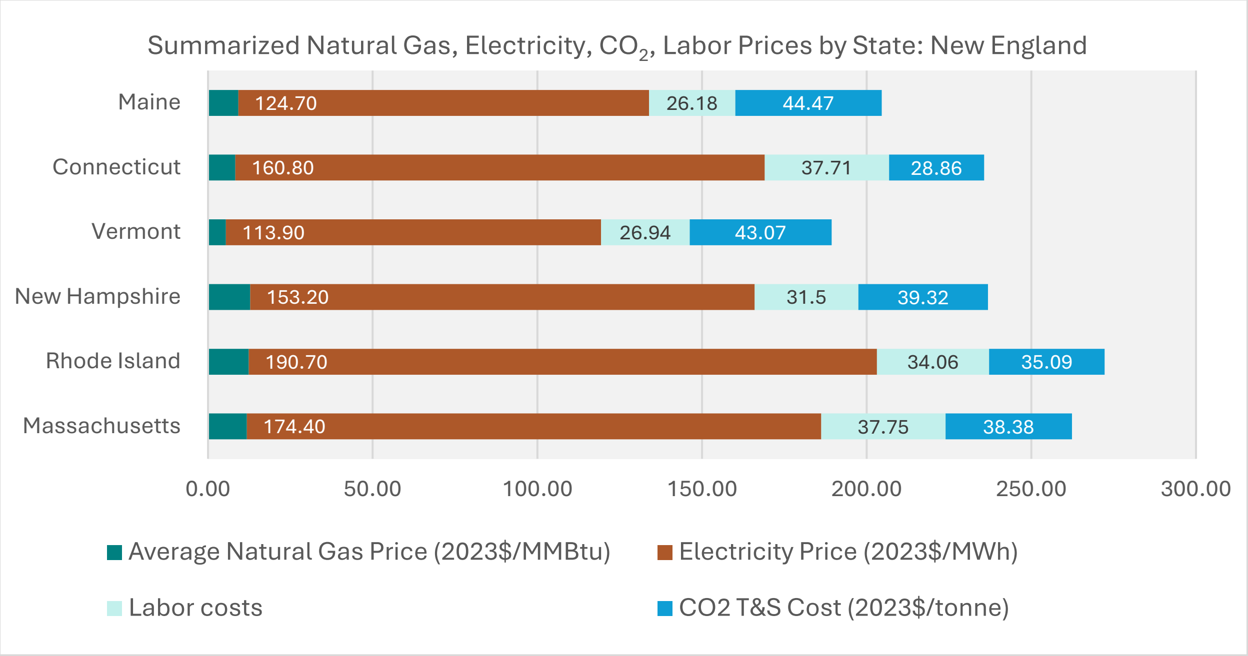


Figure 20. Summarized input prices utilized in New England state-level fuel case analysis

Electricity costs have the greatest influence on overall fuel pathway economics across New England. States such as Rhode Island and Massachusetts experience the highest fuel production costs, driven primarily by elevated electricity prices in these regions. Conversely, natural gas-based pathways are most cost-effective in Vermont, which benefits from having the lowest natural gas prices among all New England states.

PADD 1a: New England Resource Potential v. Cost

Maine

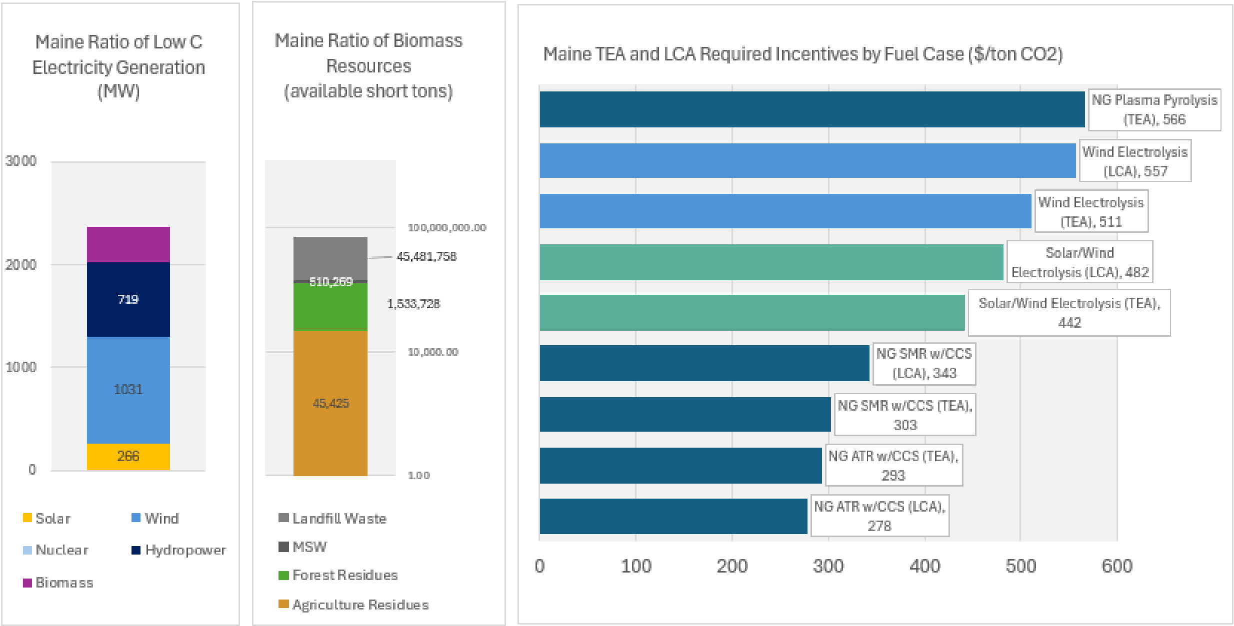


Figure 21. Maine findings summary

Near-Term Fuel Pathways

With the exception of NG SMR and NG ATR w/ CCS, estimated levelized costs and required incentives for H_2 and RNG cases are more similar for Maine compared to other East Coast states.

H_2 produced via NG SMR w/ CCS or ATR w/ CCS are the most economical cases considered. However, when focusing on fuel pathways that do not rely on CO_2 transport and storage infrastructure, electrolytic H_2 presents lower estimated levelized costs and required incentives compared to other H_2 fuel cases, including NG Plasma Pyrolysis (~40/MMBTU H_2, $566/ton CO_2).

Low C electrolytic H_2 with wind/solar mix is found to require lower incentives, but current wind generation significantly exceeds in-state solar power generation.

Future Opportunities

Maine's abundant agricultural and forest residues represent a significant resource for expanding RNG and H_2 production. As technology advances and cost reductions are realized, these biomass-based pathways could play a critical role in diversifying Maine's low-carbon fuel portfolio and enhancing energy resilience.

Vermont

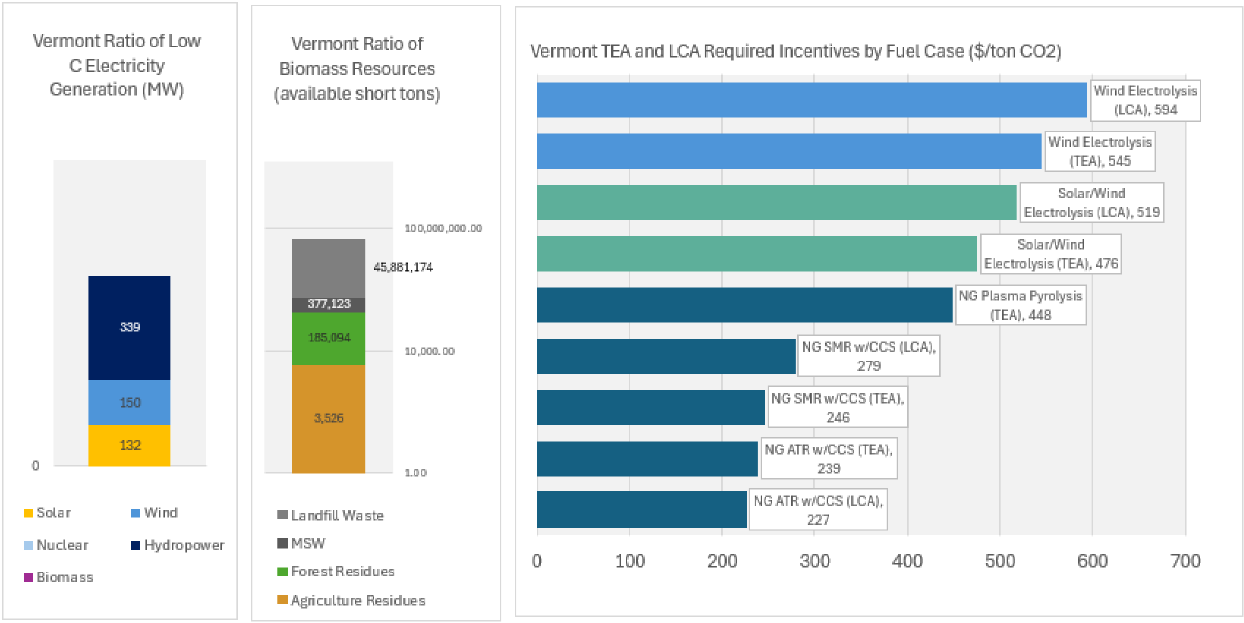


Figure 22. Vermont findings summary

Near-Term Fuel Pathways

H_2 produced via natural gas SMR w/ CCS or ATR w/ CCS are the most economical cases considered. However, when focusing on fuel pathways that do not rely on CO_2 transport and storage infrastructure, natural gas plasma pyrolysis is the next most economical pathway. This is largely due to Vermont's advantage of having the lowest average natural gas price among New England states. This is followed by electrolytic H_2 pathways.

For electrolytic H_2, a mix of wind and solar generation requires comparatively lower incentives to achieve cost parity. However, hydropower is the dominant renewable electricity source in Vermont.

Future Opportunities

Increasing solar and wind generation can reduce the cost of electrolytic H_2, improving its long-term viability. Leveraging agricultural and forest residues and landfill waste can also enhance RNG production.

Massachusetts

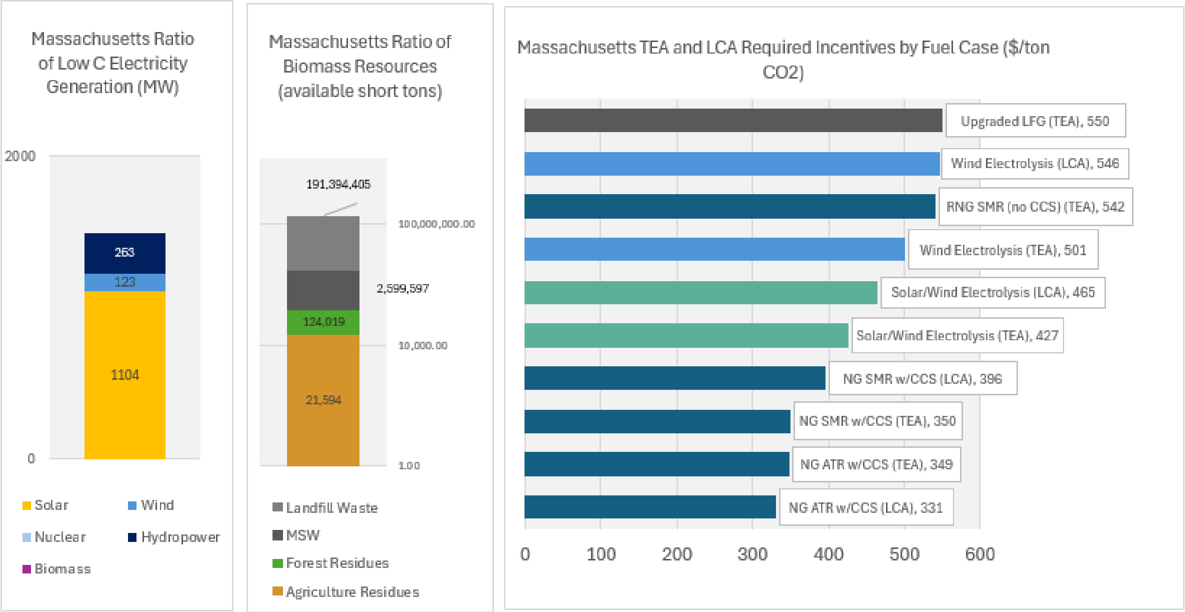


Figure 23. Massachusetts state findings

Near-Term Fuel Pathways

With no in-state natural gas reserves, Massachusetts relies on natural gas sourced from the Marcellus shale, as well as Canada.

H_2 produced via NG SMR w/ CCS or ATR w/ CCS are the most economical cases considered. While Massachusetts does not possess underground storage, the closest estimated CO_2 storage potential is found in the neighboring state of New York in the form of depleted oil and gas reservoirs.

For fuel pathways that avoid reliance on CO_2 transport and storage infrastructure, electrolytic H_2 produced using renewable electricity (primarily solar and wind) emerges as the next most economical alternative. Within this category, a hybrid mix of wind and solar generation generally requires lower financial incentives to achieve cost parity with fossil-based H_2 compared to single-source renewable strategies. However, hydropower is the dominant renewable electricity source in Massachusetts.

Future Opportunities

Increasing solar and wind generation can reduce the cost of electrolytic H_2, improving its long-term viability. Leveraging more agricultural residues and landfill waste, can significantly enhance RNG production, providing a complementary pathway for reducing emissions in sectors where H_2 adoption may be slower.

New Hampshire

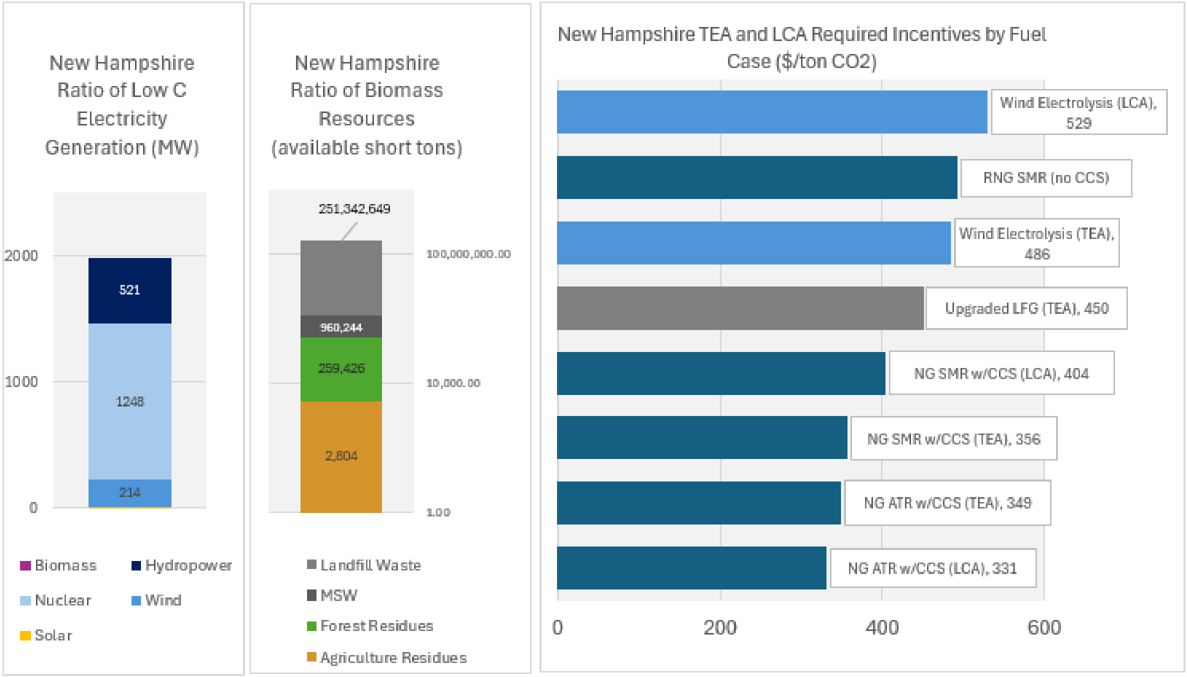


Figure 24. New Hampshire state findings

Near-Term Fuel Pathways

New Hampshire has no existing natural gas production and relies on natural gas sourced from the Marcellus Shale and Canada. H_2 produced via NG SMR w/ CCS or ATR w/ CCS are the most economical cases considered. However, the closest estimated CO_2 storage is depleted oil and gas reservoirs located in New York. For fuel pathways that avoid reliance on CO_2 transport and storage infrastructure, RNG derived from LFG upgrading emerges as the next most economical alternative ($450/MMMBTU). Following RNG, electrolytic H_2 produced using wind power offers a promising solution ($486/MMBTU). New Hampshire is well-positioned to capitalize on electrolytic H_2, given its substantial wind and hydropower generation capacity,

Future Opportunities

Expanding wind and hydroelectric generation will further reduce the cost of electrolytic H_2, enhancing its competitiveness and long-term viability. In parallel, increasing the utilization of agricultural residues, forest biomass, and landfill waste can significantly boost RNG production.

Connecticut

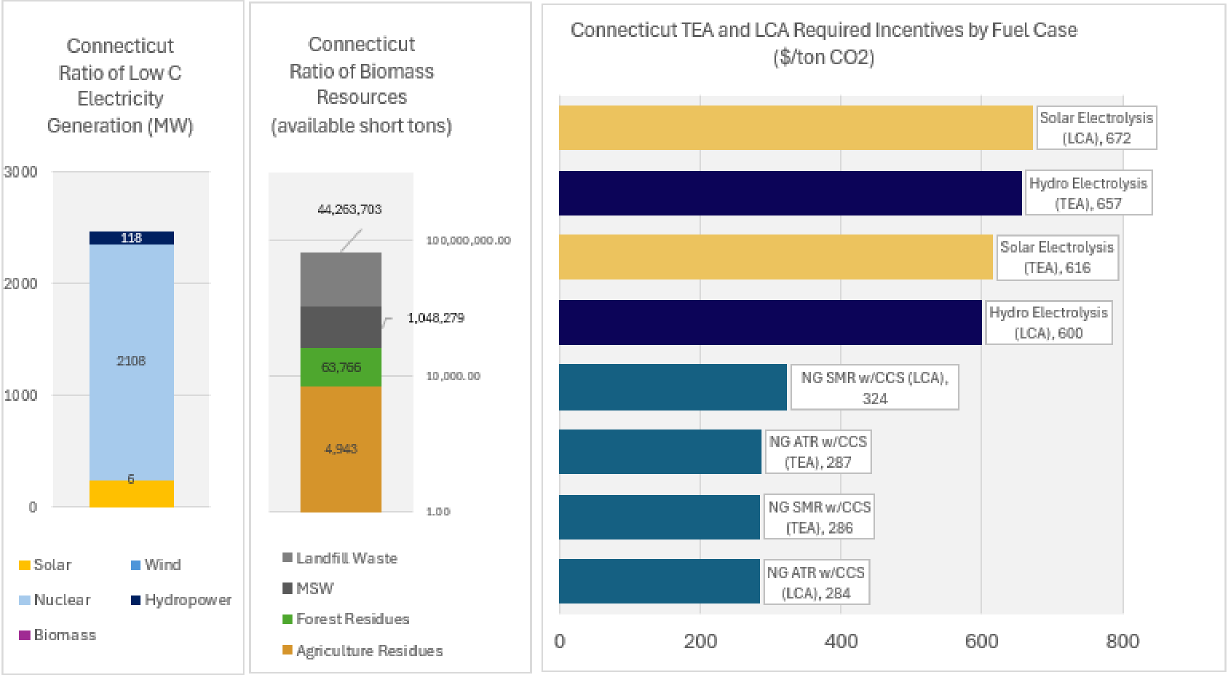


Figure 25. Connecticut state findings

Near-Term Fuel Pathways

Having no existing natural gas production, Connecticut largely receives natural gas through New York transmission pipelines, sourcing from the Marcellus Shale (West Virginia, Pennsylvania), Gulf Coast states, and Canada.

H_2 produced via NG SMR or ATR w/ CCS are the most economical cases considered. However, electrolytic H_2 is the most economical fuel pathway to avoid reliance on CO_2 transport and storage infrastructure. However, estimated CO_2 storage potential in Connecticut is limited, with the closest storage potential being associated with depleted oil and gas reservoirs in New York.

While H_2 from solar-powered electrolysis is projected to require fewer incentives than electrolysis using nuclear electricity, nuclear power is the most abundant source of low-carbon electricity in Connecticut.

Future Opportunities

Agricultural and forest residues offer significant potential for expanding RNG and H_2 production, contingent on achieving cost reductions and technology improvements.

Rhode Island

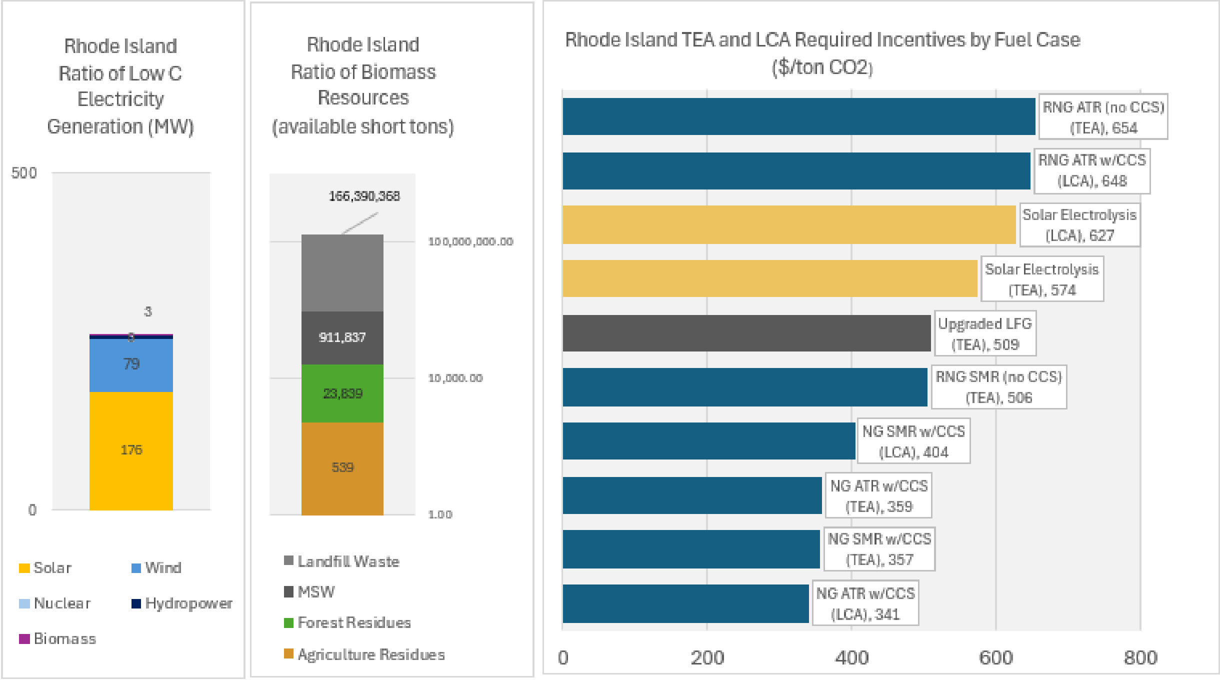


Figure 26. Rhode Island state findings

Near-Term Fuel Pathways

Rhode Island has no existing natural gas production and relies on natural gas sourced from the Marcellus Shale and New York. Estimated required incentives for H_2 production in Rhode Island are similarly higher across different H_2 fuel cases. Due to geographical limitations, RNG produced via upgraded landfill gas and electrolytic H_2 produced powered by existing solar facilities may be stronger opportunities ($509-574/MMBTU).

Future Opportunities

Scaling up landfill gas upgrading can increase RNG production. By prioritizing RNG and electrolytic H_2, Rhode Island can avoid heavy reliance on carbon capture and CO_2 transport infrastructure.

PADD 1b: Central Atlantic

New York, Pennsylvania, New Jersey, Delaware, Maryland

Case Study Analysis: Central Atlantic State Price Inputs

Figure 31 below summarizes Central Atlantic state level costs for natural gas, electricity, transportation and storage of CO_2, and average labor rates, each of which contribute to the fuel case technoeconomic findings.

Among the Central Atlantic states, New York and Pennsylvania exhibit the lowest electricity prices, which helps reduce total fuel production costs. In contrast, New Jersey stands out for having the lowest natural gas prices across the region, offering a competitive advantage for fuel production scenarios that rely on natural gas.

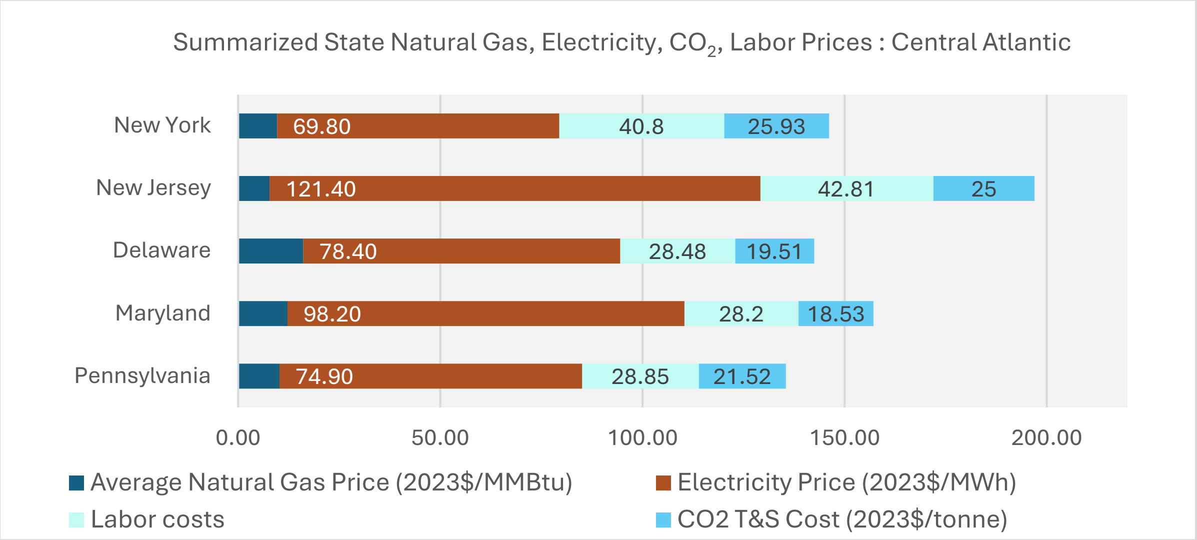


Figure 27. Summarized input prices utilized in Central Atlantic state-level fuel case analysis

When considering the combined effect of all cost drivers (natural gas, electricity, labor, and CO_2 T&S), Pennsylvania emerges as the most cost-advantaged state. This is due to its relatively low prices in all major categories, including natural gas and electricity, as well as lower labor rates and CO_2 transportation and storage costs. These favorable conditions position Pennsylvania as a leading candidate for cost-effective fuel pathway deployment within the Central Atlantic.

PADD 1b: Central Atlantic Resource Potential v. Cost

New York

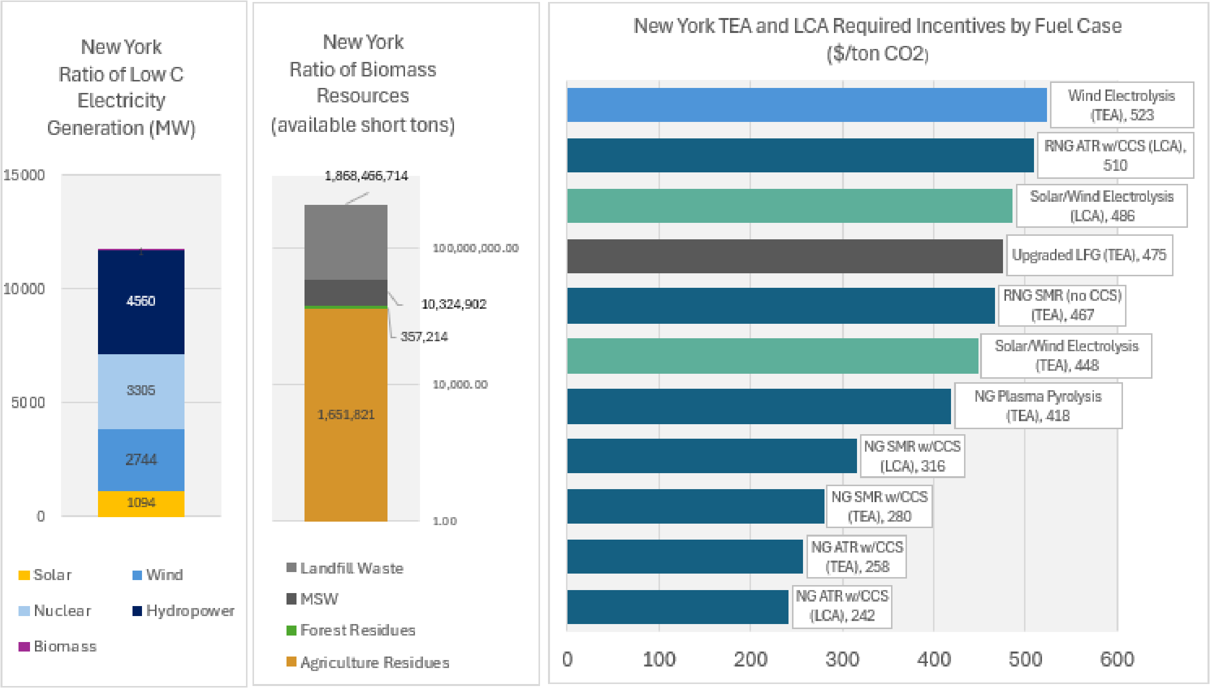


Figure 28. New York state findings

Near-Term Fuel Pathways

Due to New York existing over a portion of the larger Marcellus Shale formation, the state heavily relies on affordable natural gas sourced from other bordering states such as Pennsylvania and also from Canada. Low-carbon H_2 via natural gas-based SMR with CCS and ATR with CCS are identified as the lowest-cost H_2 production options and may leverage existing in-state natural gas reserves and storage fields. Given affordable natural gas prices in New York, these pathways achieve levelized costs of $20-22/MMBTU with incentives of $258-$280 per ton of CO_2 abated. Without CCS, SMR levelized costs increase, aligning with natural gas plasma pyrolysis at $30-33/MMBTU.

When considering RNG-fed SMR or ATR cases, electrolytic H_2 and RNG produced via landfill gas are found to be similarly competitive. For instance, electrolytic H_2 powered by solar or wind is more economical ($448/ton CO_2 abated) than RNG-fed ATR with CCS and comparable to RNG-fed ATR without CCS. RNG from upgraded landfill gas in New York is estimated to have levelized costs of $34/MMBTU, requiring incentives of $475 per ton of CO_2 abated.

Future Opportunities

New York offers diverse biomass resources and significant untapped low-carbon electricity potential. Developing centralized co-production facilities could enhance cost efficiency for RNG derived from agricultural and forest residues while mitigating land-use challenges. Per New York State's 2025 Energy Plan, the state prefers waste-based feedstocks for alternative fuel production.[2] The state also plans to focus on developing wind, solar, energy storage, advanced nuclear, and revitalizing older combustion power plants to meet future energy demand needs.

Pennsylvania

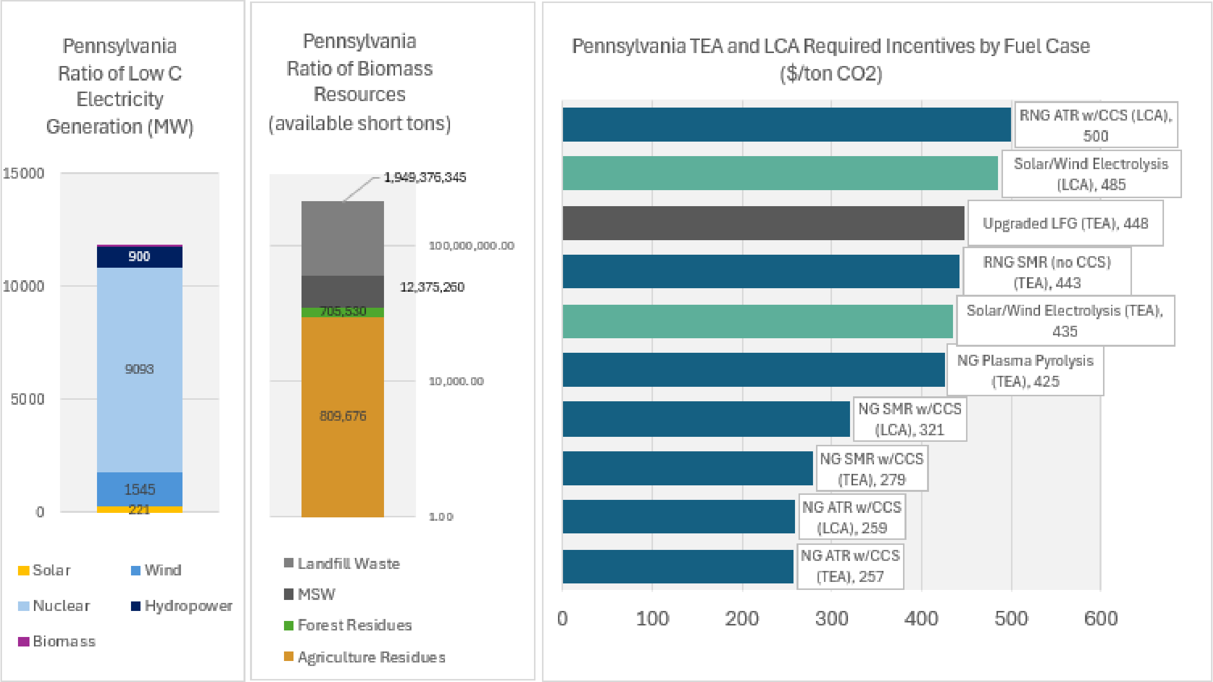


Figure 29. Pennsylvania state findings

Near-Term Fuel Pathways

Affordable natural gas prices, abundant reserves, and ample storage give Pennsylvania a regional edge in producing H_2 via natural gas ATR with CCS and SMR with CCS, at estimated costs of \$21-\$22/MMBTU and \$257-\$278 per ton of CO_2 abated. Estimated in-state potential CO_2 storage is in the form of saline aquifers and depleted oil and natural gas reservoirs. As of 2022, the Pennsylvania Department of Environment expressed an interest in applying for Class VI well supremacy with the EPA.[3] Once

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[2] 2025 Energy Plan - New York State New Energy Plan

[3] General Assembly of the Commonwealth of Pennsylvania 2022 Act

granted, Class VI well supremacy would encourage further adoption of CCS-dependent H_2 production pathways.

For H_2 production cases excluding CCS in Pennsylvania, natural gas plasma pyrolysis offers the lowest estimated levelized cost ($31/MMBTU) and incentive requirement ($425 per ton CO_2 abated).

RNG from upgraded landfill gas is slightly more expensive ($32/MMBTU) and requires marginally higher incentives ($448 vs. $425 per ton CO_2 abated).

While electrolytic H_2 from solar and wind appears more economical, Pennsylvania’s existing low-carbon electricity is predominantly nuclear. Due to higher variable O&M costs, nuclear-based electrolysis results in higher levelized costs ($51/MMBTU) within the state.

Future Opportunities

Currently, Pennsylvania’s limited solar and wind generation constrains the near-term potential for electrolytic H_2 production. Increasing solar and wind capacity could significantly enhance the competitiveness of electrolytic H_2 by leveraging lower-cost renewable electricity. This shift would not only reduce production costs but also align with broader decarbonization goals, creating opportunities for H_2 to play a larger role in Pennsylvania’s clean energy strategy. Strategic investments in renewable infrastructure and grid integration will be critical to unlocking this potential.

New Jersey

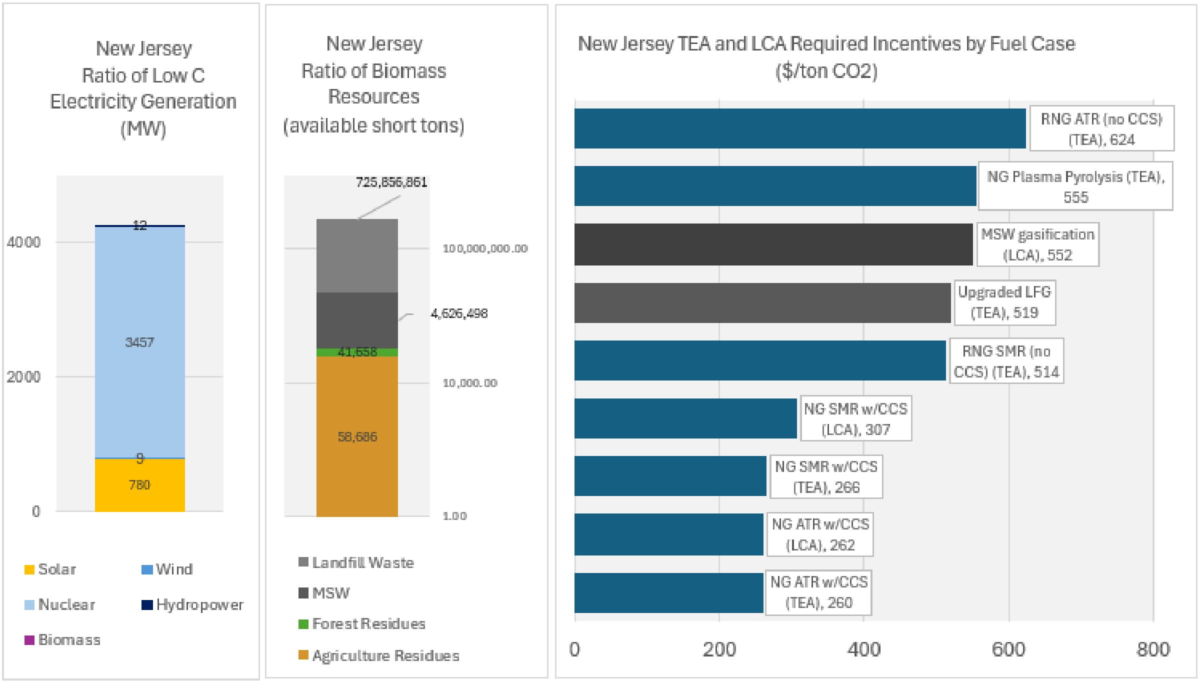

Figure 30. New Jersey state findings

Near-Term Fuel Pathways

Having no existing natural gas reserves, New Jersey largely sources natural gas from the Marcellus Shale, as well as Canada. H_2 produced via natural gas fed SMR w/ CCS and ATR w/CCS demonstrate similarly low levelized costs at approximately \$20/MMBTU, with required incentives in the range of \$260-\$266 per ton of CO_2 abated. Estimated in-state CO_2 storage potential for New Jersey is negligible. However, there is CO_2 storage potential in the form of saline aquifers and depleted oil and gas reservoirs in the neighboring state Pennsylvania.

For fuel pathways excluding CCS, RNG produced from upgraded LFG shows slightly lower levelized costs and required incentives (\$36/MMBTU, \$519/ton CO_2 abated) compared to NG plasma pyrolysis (\$38/MMBTU, \$554/ton CO_2 abated). Among H_2 pathways without CCS, RNG-fed SMR offers the lowest levelized cost and incentive requirement (\$36/MMBTU, \$514/ton CO_2 abated).

Future Opportunities

Current nuclear power generation in New Jersey exceeds solar output by more than three orders of magnitude. However, the estimated levelized cost of electrolytic H_2 from nuclear power (\$51/MMBTU) is significantly higher than from solar (\$42/MMBTU) or wind (\$35/MMBTU), primarily due to higher projected variable O&M costs. Looking ahead, prioritizing wind generation in New Jersey could improve the economics of H_2 production via electrolysis powered by wind.

Maryland

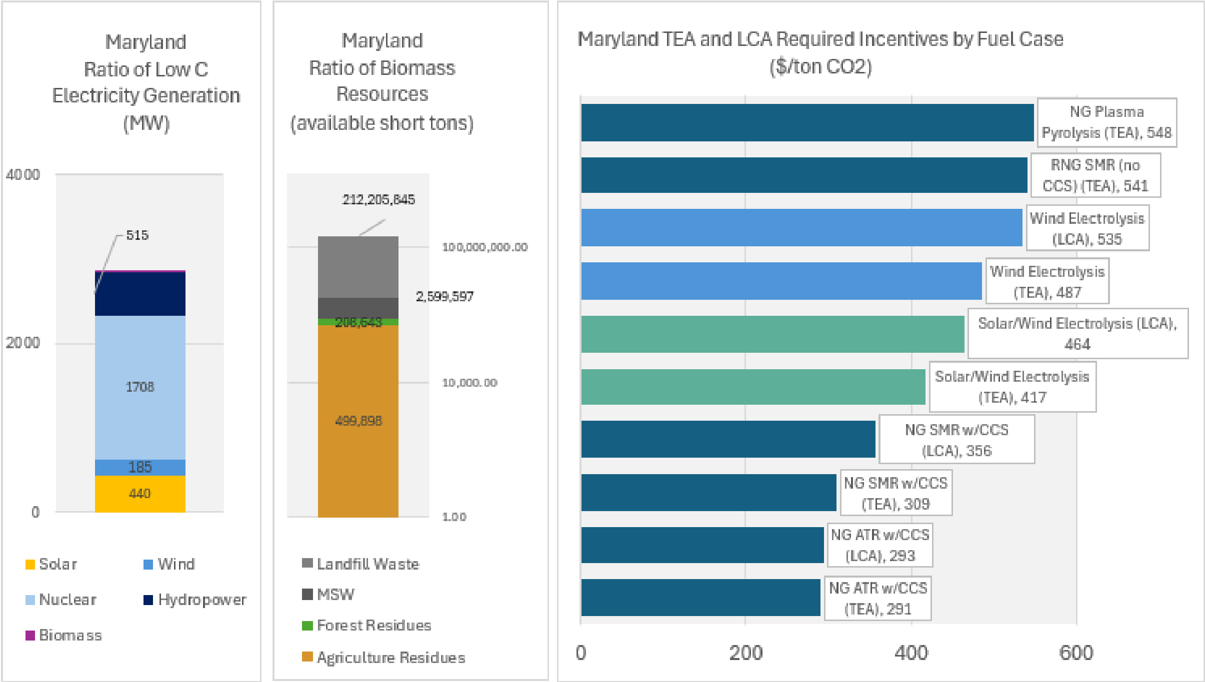

Figure 31. Maryland state findings

Near-Term Fuel Pathways

Maryland has no existing natural gas production and relies on natural gas originating from the Marcellus Share (West Virginia, Pennsylvania) and Canada.

In Maryland, the lowest fuel levelized costs and required incentives are associated with H_2 produced via NG SMR with CCS ($24/MMBTU, $291/ton CO_2 abated) and NG ATR with CCS ($25/MMBTU, $309/ton CO_2 abated). However, estimated CO_2 storage potential is limited to minimal saline aquifers. For cases excluding CCS, electrolytic H_2 from wind shows the lowest levelized cost ($36/MMBTU), followed by NG SMR and NG plasma pyrolysis, both at approximately $40/MMBTU. Notably, NG plasma pyrolysis yields a lower calculated CI score compared to NG SMR without CCS.

Although wind-based electrolysis offers the most cost-effective non-CCS option, current wind generation in Maryland is minimal relative to low-carbon electricity sources such as nuclear and solar.

Future Opportunities

Expanding wind and solar generation can further reduce electrolytic H_2 costs and avoid dependence on carbon capture and storage infrastructure. Additionally, investing in pyrolysis technologies can enhance reliability by supporting intermittent renewable generation.

Delaware

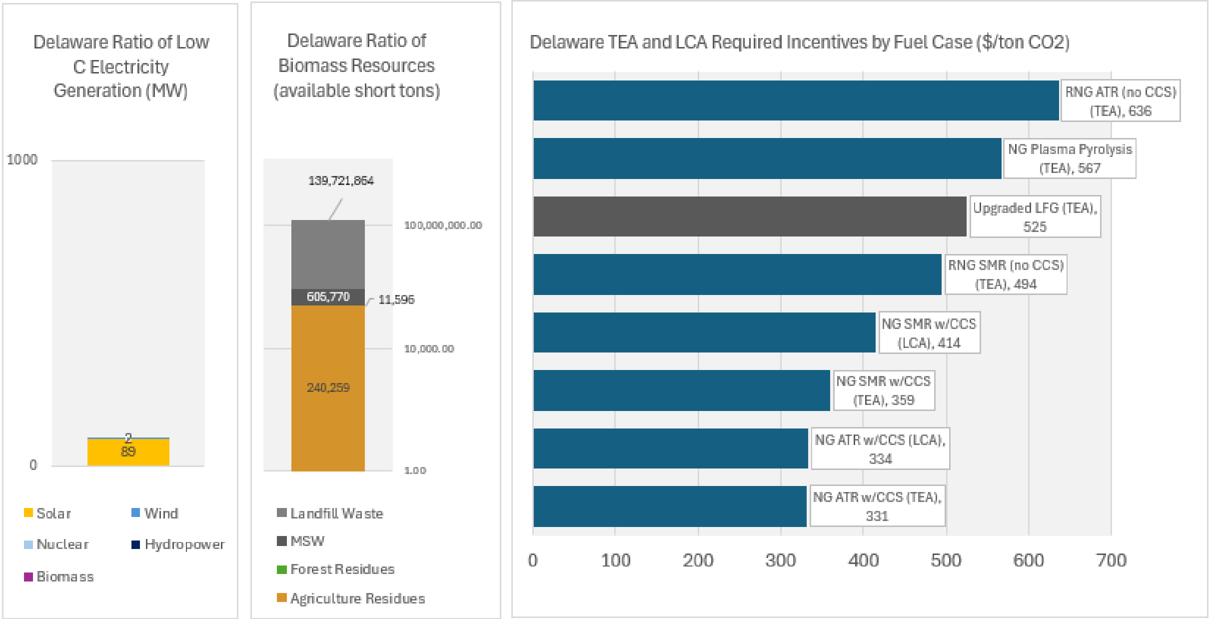

Figure 32. Delaware state findings

Near-Term Fuel Pathways

Delaware relies on natural gas originating from the Marcellus Shale (Pennsylvania) and Canada. H_2 produced via NG SMR w/CCS and NG w/ATR demonstrated the lowest fuel levelized costs ($29-31/MMBTU) and required incentives ($331-359/ton CO_2 abated). However, estimated CO_2 storage potential in Delaware is limited. For fuel pathways excluding CCS, similar levelized costs are observed for RNG SMR without CCS ($39/MMBTU), NG plasma pyrolysis ($43/MMBTU), and RNG from LFG ($41/MMBTU). Among these, RNG-fed SMR without CCS requires the smallest incentives to achieve cost parity with natural gas in Delaware.

The limited availability of low-carbon electricity generation in Delaware constrains the scalability of electrolytic H_2 production.

Future Opportunities

Upgrading LFG offers additional decarbonization potential without relying on carbon capture or CO_2 transport infrastructure. In addition, leveraging agricultural residues can increase RNG production.

PADD 1c: Lower Atlantic

West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida

Case Study Analysis: Lower Atlantic State Price Inputs

Figure 37 summarizes state-level costs in the Lower Atlantic region for natural gas, electricity, CO_2 transportation and storage, and average labor rates, which are key drivers of the fuel case technoeconomic results.

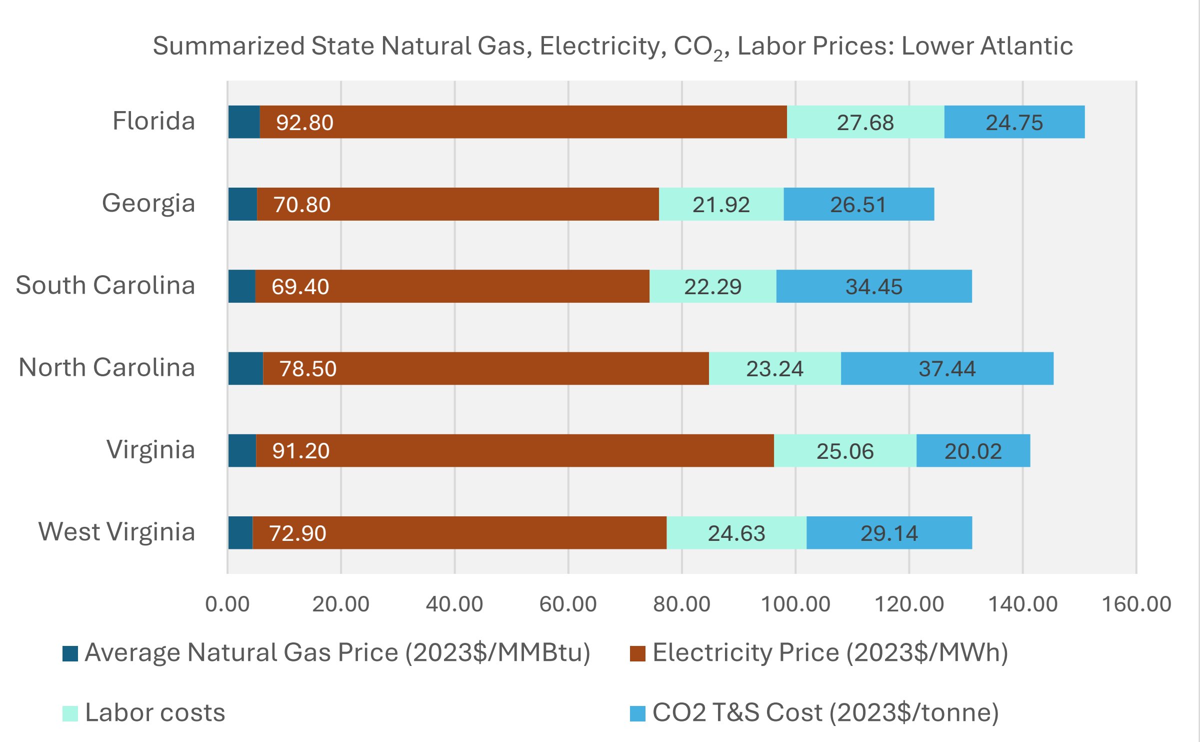

Figure 33. Summarized input prices utilized in Lower Atlantic state-level fuel case analysis

Among these states, South Carolina and Georgia offer the lowest electricity prices, helping to reduce overall fuel production costs. Conversely, West Virginia stands out with the lowest natural gas prices, providing a competitive edge for fuel pathways that rely on natural gas. When considering the combined impact of all cost factors, Georgia emerges as the most cost-advantaged state for emerging fuels deployment within the Central Atlantic region.

PADD 1c: Lower Atlantic Resource Potential v. Cost

West Virginia

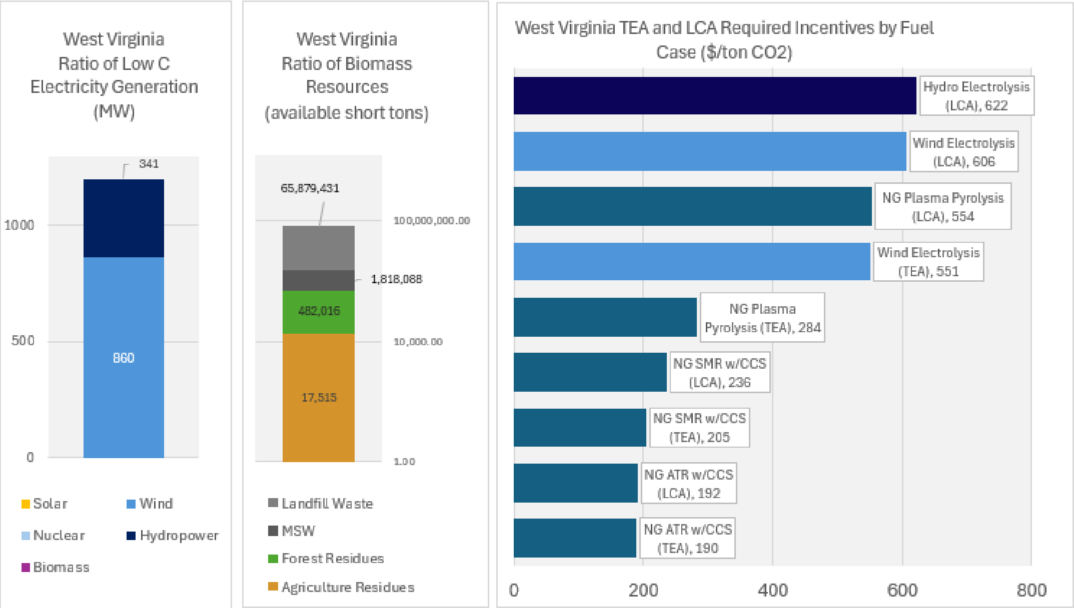

Figure 34. West Virginia state findings

Near-Term Fuel Pathways

West Virginia benefits from regionally abundant natural gas reserves, competitive gas prices, and existing wind power generation, positioning the state favorably for H_2 production through multiple pathways. The lowest fuel levelized costs and required incentives in West Virginia are associated with H_2 via NG ATR w/ CCS ($14/MMBTU, $190/ton CO_2 Abated) and NG SMR w/ CCS ($15/MMBTU, $205/ton CO_2 Abated).

When considering fuel cases excluding CCS in West Virginia, NG Plasma Pyrolysis demonstrates the lowest levelized costs ($20/MMBTU) and required incentives ($284/ton CO_2 Abated).

Prospects for electrolytic H_2 in West Virginia are expected to be associated with wind power due to existing wind power generation and lowest estimated levelized costs for electrolytic H_2 supplied by wind power ($36/MMMBTU). Electrolytic H_2 via hydropower in West Virginia demonstrates higher levelized costs ($43/MMBTU) to electrolysis via wind power.

Future Opportunities

Expanding wind generation can further reduce electrolytic H_2 costs. Additionally, investing in pyrolysis technologies can enhance reliability by supporting intermittent renewable generation.

Virginia

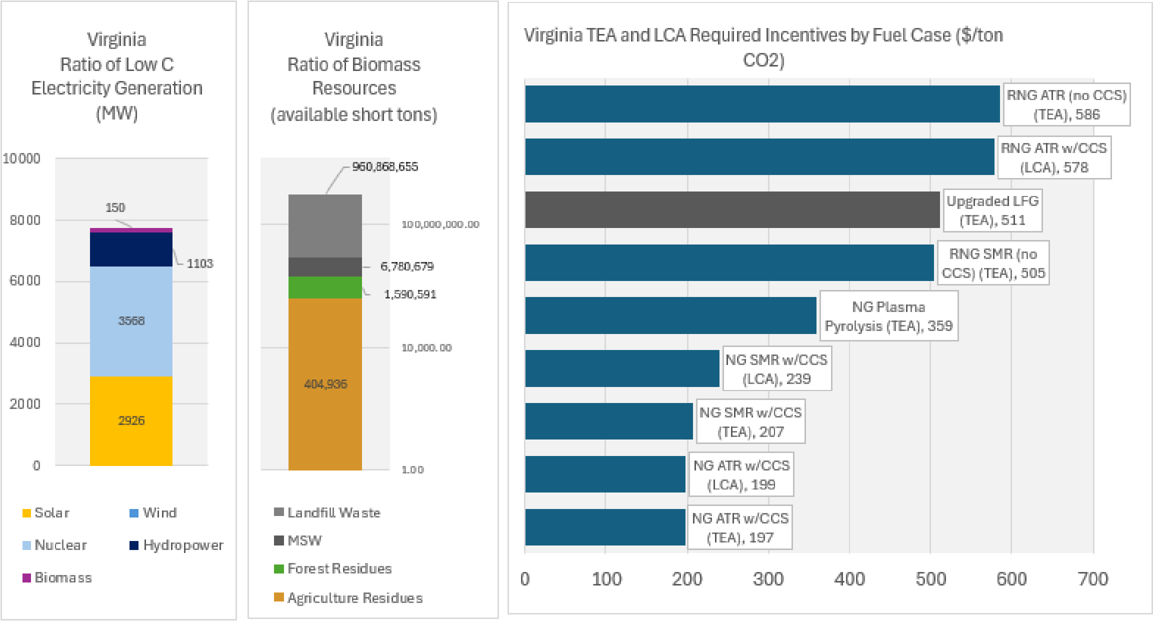

Figure 35. Virginia state findings

Near-Term Fuel Pathways

Virginia relies on in-state natural gas production as well as natural gas sourced from the Marcellus Shale (Pennsylvania, West Virginia), Gulf Coast states (Texas, Louisiana), and Oklahoma.

H_2 produced via NG SMR w/CCS and ATR w/ CCS are found to offer the lowest required incentives ($197-239/MMBTU). Virginia's estimated CO_2 storage potential is limited, with only minimal depleted oil and gas reservoirs. However, neighboring West Virginia offers additional storage potential with saline aquifers and depleted oil and gas reservoirs.

Among pathways that do not require CCS, methane pyrolysis offers the lowest cost, at approximately $25/MMBTU and $359 per ton of CO_2. Additionally, H_2 production via RNG-based SMR without CCS is more economically competitive than electrolytic H_2 in Virginia.

Future Opportunities

With the expansion of solar generation, alternative land use strategies, and available incentives, electrolytic H_2 from solar power could become a cost-effective option in Virginia over time. The Virginia Department of Energy has announced three planning awards to advance clean H_2 production, storage, and use in Southwest Virginia.[4] It is anticipated that these efforts will identify H_2 opportunities for the region. In addition, with incentives, RNG production via LFG upgrades can be a cost-effective alternative to the H_2 pathways.

North Carolina

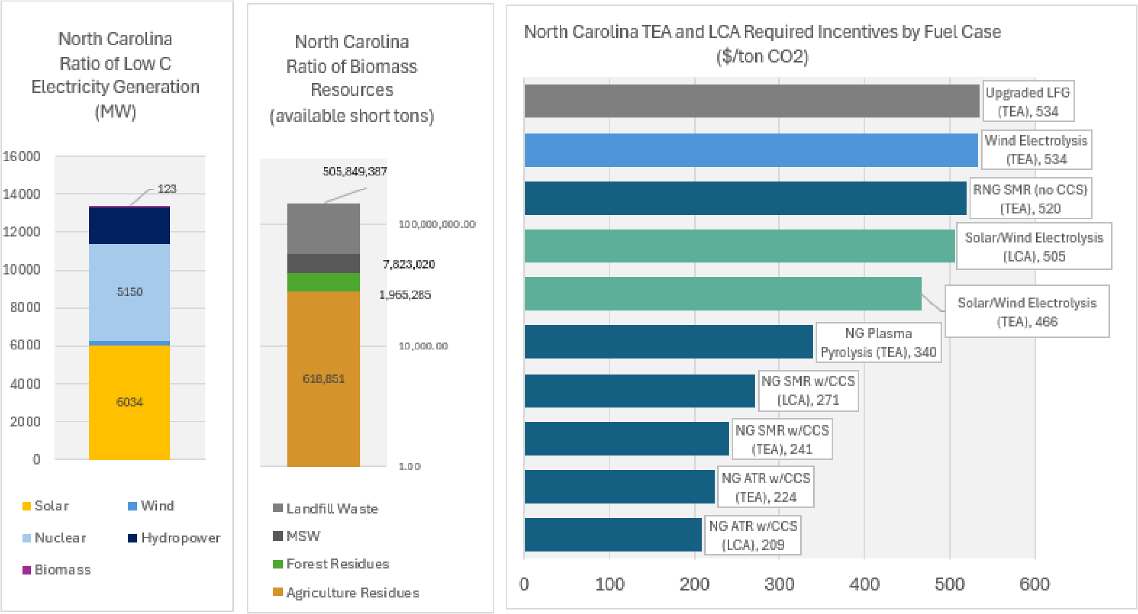

Figure 36. North Carolina state findings

Near-Term Fuel Pathways

North Carolina depends on natural gas sourced from the Marcellus Shale (Pennsylvania, West Virginia, Ohio), Gulf Coast states (Louisiana, Texas), and Canada.

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[4] https://www.energy.virginia.gov/public/documents/newsroom/2025/Virginia%20Energy%20Awards%20750k%20in%20Southwest%20Virginia%20Hydrogen%20Hub%20Planning%20Grants.pdf

NG SMR with CCS and NG ATR with CCS are identified as the lowest-cost H_2 production pathways in North Carolina, with levelized costs of approximately $17-$18/ MMBTU. These pathways also correspond to the lowest estimated incentives required to achieve cost parity with natural gas in the state, ranging from $224-$240/MMBTU. However, estimated CO_2 storage potential in North Carolina is limited. For pathways that do not incorporate CCS, natural gas plasma pyrolysis offers the most competitive economics, with levelized costs near $24/MMBTU and associated incentives of about $340 per ton of CO_2.

Future Opportunities

Expanding solar and wind generation can further reduce electrolytic H_2 costs. Additionally, investing in pyrolysis technologies can enhance reliability by supporting intermittent renewable generation.

South Carolina

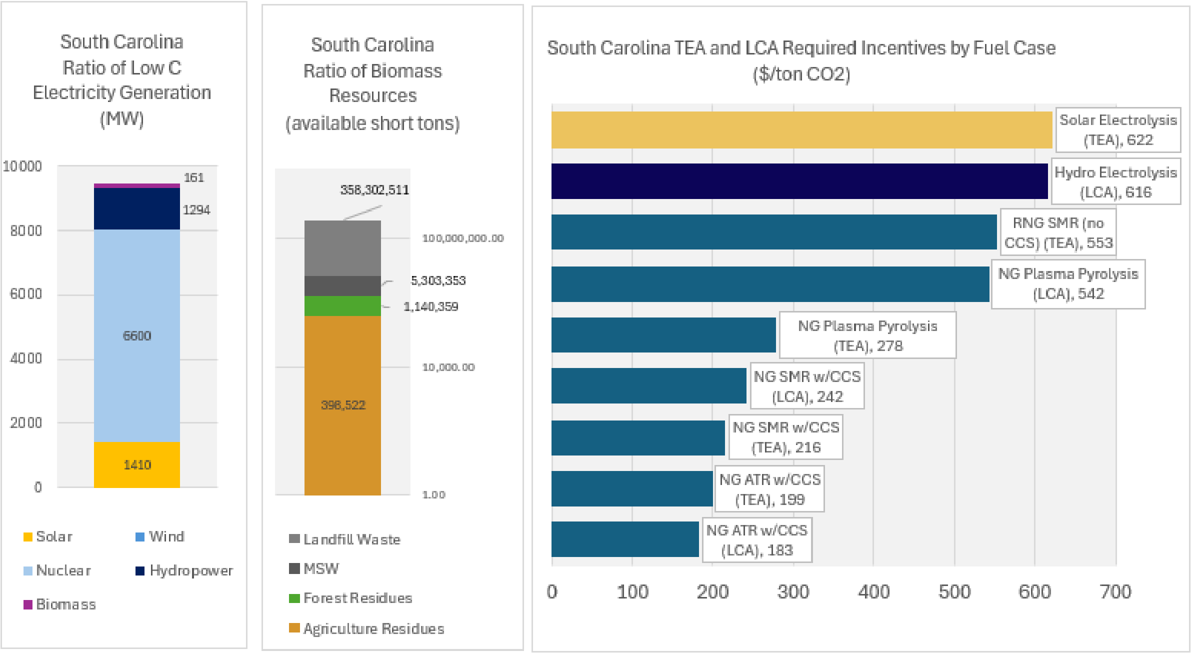


Figure 37. South Carolina state findings

Near-Term Fuel Pathways

With no in-state natural gas production, South Carolina sources natural gas from Gulf Coast states (Louisiana, Mississippi, Alabama), which is delivered via transmission lines crossing through Georgia. Unlike other East Coast states, South Carolina does not heavily rely on the Marcellus Shale. Additionally, estimated in-state CO_2 storage potential is limited to saline aquifers.

Compared to other states in the region, South Carolina generally has the lowest levelized costs across fuel cases, with overall costs of about $15/MMBtu for reforming and about $19/MMBtu for plasma pyrolysis. However, when focusing on fuel pathways that do not rely on CO_2 transport and storage infrastructure, NG plasma pyrolysis is the most economical emerging fuel pathway with the lowest required incentive ($278/ton CO_2).

Future Opportunities

Current H_2 demand in South Carolina is low, at approximately 0.11 petajoules. Introducing targeted incentives to encourage adoption could reduce emissions, especially given the state's lowest H_2 production costs compared to other East Coast states.

Georgia

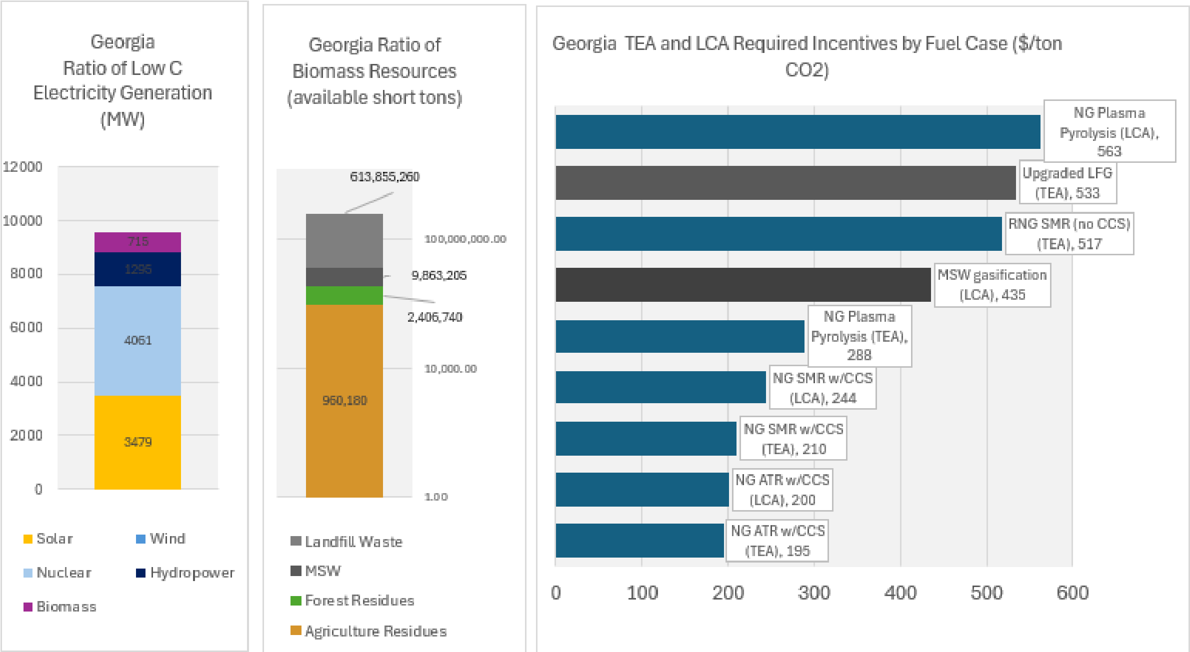


Figure 38. Georgia state findings

Near-Term Fuel Pathways

Natural gas production in Georgia plays a vital role in supplying affordable fuel to various end use sectors. Georgia also sources natural gas from several states in the East Coast (Pennsylvania, West Virginia) as well as from Gulf Coast states (Alabama, Texas, Louisiana).

As a result of competitive natural gas prices, natural gas SMR and ATR with CCS represent the most cost-effective pathways for H_2 production. In-state potential for CO_2 storage is estimated in the form of saline and fossil underground storage sites in the southern portion of the state. Plasma pyrolysis emerges as a promising alternative pathway which does not require CCS, offering potential advantages in terms of lower emissions and scalability, though it is less cost-competitive compared to SMR and ATR with CCS.

For RNG, anaerobic digestion of MSW and LFG are two cost-effective options. Both options capitalize on Georgia’s substantial MSW resource base, creating synergies between waste management and renewable fuel production.

Future Opportunities

While Georgia currently lacks significant wind generation capacity, the state possesses strong technical potential for wind power development. Unlocking this resource could significantly enhance the feasibility of electrolytic H_2 production in the long term, particularly when paired with grid decarbonization efforts and renewable integration strategies.

Georgia also possesses considerable agricultural biomass resources. While near-term costs for RNG derived from agricultural residue digestion remain relatively high compared to other feedstocks, technological advancements, economies of scale, and policy incentives could reduce these barriers over time. Developing robust supply chains for biomass and exploring co-location opportunities with existing agricultural operations may further improve cost competitiveness.

Florida

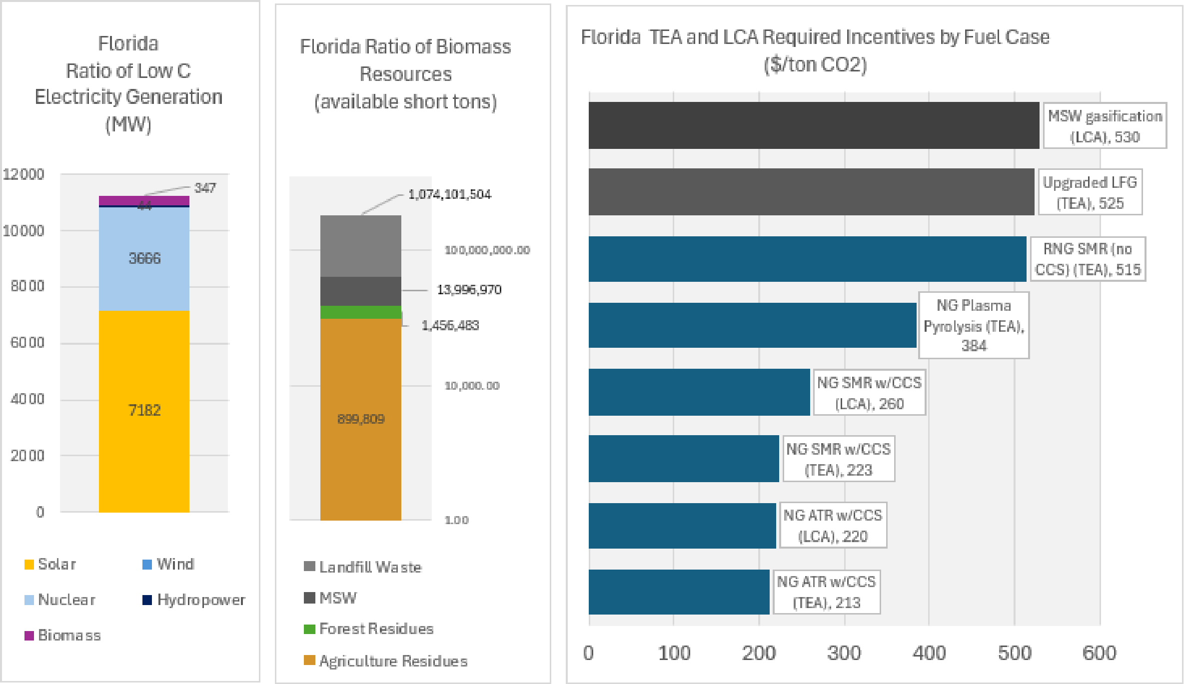


Figure 39. Florida State Findings

Near-Term Fuel Pathways

Natural Gas SMR and ATR with CCS represent the most cost-effective pathways for H_2 production. Estimated in-state CO_2 storage potential is identified in the form of saline underground storage and extends throughout the state.

Plasma pyrolysis emerges as a promising alternative pathway, though it is less cost-competitive compared to SMR and ATR with CCS. For RNG, upgrading of LFG could be a cost-effective option by leveraging the state's substantial waste generation.

Future Opportunities

Florida's strong solar resource, which exceeds that of many other East Coast states, positions the state favorably for electrolytic H_2 production as renewable penetration grows. Expanding solar and wind generation capacity will enhance the economics of electrolysis by lowering renewable electricity costs and improving grid flexibility. Over the long term, this could enable Florida to become a competitive hub for electrolytic H_2, complementing natural gas-based pathways and supporting decarbonization across multiple sectors.

Producing and Delivering Emerging Fuels in Each State

Production Emissions

To establish upper and lower bounds for RNG emissions, two distinct scenarios were modeled: RNG-1A, representing woody biomass gasification via thermal conversion, and RNG-1B, sourced from MSW through anaerobic digestion. These cases provide contrasting perspectives on feedstock origin and conversion technology, which significantly influence lifecycle emissions. For H_2, an additional case (H2-8) was modeled to represent production using a mix of low-carbon electricity sources, excluding nuclear power. Parallel scenarios (H2-8a–8e) isolate individual renewable sources such as solar, wind, hydro, and biomass to assess sensitivity to electricity mix.

Across the East Coast region, most states exhibit less than 5% variation in GHG intensity for low-carbon H_2 pathways due to relatively uniform grid mixes dominated by PJM, Independent System Operator New England (ISO-NE), and New York Independent System Operator (NYISO). However, scenarios using biomass-generated electricity (H2-8e) show up to 30% variation, largely driven by differences in biogenic carbon accounting and feedstock origin in state-specific inventories. SNG pathways display highly uniform results across states, with less than 1% variation, reflecting the dominance of process-level assumptions over regional factors. The streamlined modeling approach adjusted electricity-related emissions externally using literature-based carbon intensities (e.g., solar: 15 gCO_2e/MJ; wind: 11; nuclear: 12), while non-electricity contributions were retained from the original OpenLCA model. This method captures variability in energy sources but does not fully account for differences in capture technologies or retrofit configurations, which could influence real-world outcomes.

Based on modeled scenarios, the regional average CI for H_2 production is 3.12 kg CO_2e/kg H_2, below DOE's clean H_2 threshold of 4.0 kg CO_2e/kg H_2. SNG averages 15.89 kg CO_2e/kg SNG, while RNG averages 5.70 kg CO_2e/kg RNG. On an energy basis, these correspond to 26 g CO_2e/MJ for H_2, 318 g CO_2e/MJ for SNG, and 114 g CO_2e/MJ for RNG, which appear higher than reported production averages for conventional natural gas (6.1–34.2 g CO_2e/MJ)(Khutal et al. 2024b). However, these comparisons are misleading if limited to production emissions. Conventional natural gas combustion emits approximately 56 kg CO_2/GJ (UK Forest Research 2025) when including upstream methane leakage and processing. In contrast, H_2 offers near-zero combustion emissions, and RNG can achieve net-negative emissions when system expansion credits are applied. Using EIA data, U.S. natural gas consumption in 2024 was over 30 trillion cubic feet (~31 EJ)(EIA 2025c). Replacing just 10% of this energy with clean H_2 (CI ~26 g/MJ) could abate over 150 million metric tons of CO_2 annually, assuming displacement of natural gas combustion emissions. Similarly, RNG substitution at modeled intensities could deliver significant reductions if sourced from waste streams, as RNG pathways under California LCFS have demonstrated carbon intensities as low as –194 g CO_2e/MJ, enabling net-negative emissions in some cases.

Delivery Costs

The Hydrogen Delivery Scenario Analysis Model (HDSAM), developed by ANL, was used to determine costs of H_2 transportation and delivery (Elgowainy & Reddi, 2022). Region-specific factors such as electricity prices, natural gas price, and labor costs were incorporated to adjust HDSAM values and estimate state-level data, and all prices are reported in 2023$. Aside from these adjustments, all default assumptions in the HDSAM were maintained. Both liquid and gaseous transportation and delivery options were analyzed (**Table 3**).

Table 3. Summary of liquid and gaseous delivery costs by state in East Coast

State	Liquid Delivery Transport Cost (2023$/kg H_2)	Gaseous Delivery Transport Cost (2023$/kg H_2)
Connecticut	4.79	3.11
Delaware	3.42	2.86
Florida	3.09	2.25
Georgia	2.47	1.91
Maine	3.76	2.30
Maryland	3.47	2.56
Massachusetts	5.00	3.67
New Hampshire	4.76	2.83
New Jersey	4.56	3.56
New York	3.87	3.23

North Carolina	2.66	1.91
Pennsylvania	3.15	2.53
Rhode Island	5.09	3.62
South Carolina	2.52	1.69
Vermont	3.77	2.10
Virginia	2.88	2.08
West Virginia	2.87	1.78

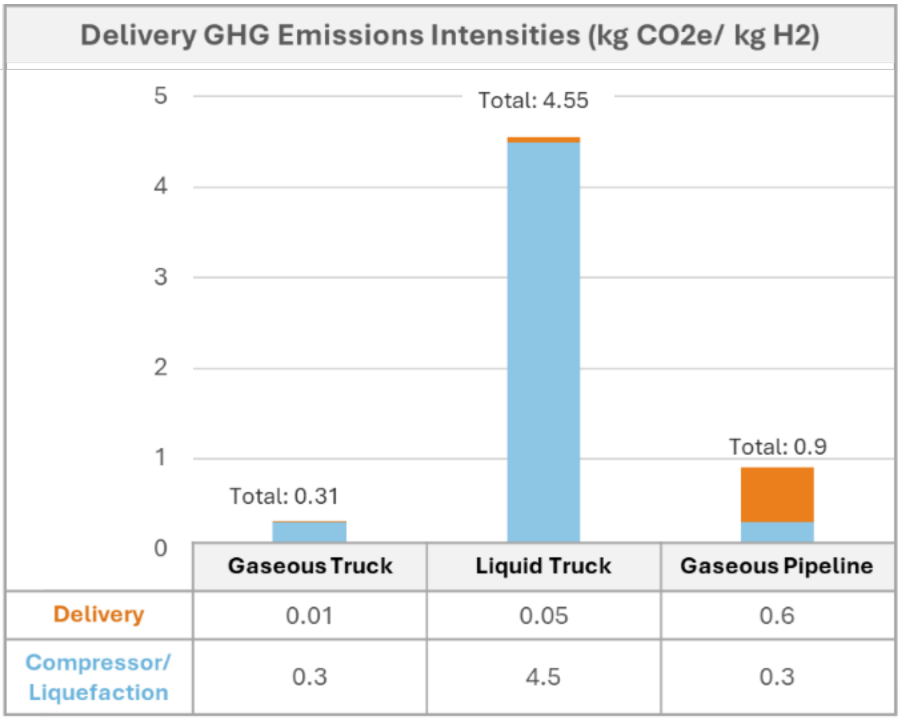
The liquid option includes a H_2 liquefier at the production facility, a liquid H_2 terminal, and a liquid H_2 delivery truck. The gaseous option includes compression at the production facility, a gaseous H_2 terminal, and transport via tube truck.

SNG and RNG projects may have additional pipeline interconnection costs, depending on the location of the plant, existing infrastructure availability, and scale of the project (Lowell & Jones, 2019). For the SNG cases (SNG-1–SNG-4), the plant can be co-located near the CO2 point source, reducing CO2 transportation costs and being able to take advantage of existing pipeline infrastructure that already exists 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) (Lowell & Jones, 2019).

For the biomass to RNG case (RNG-2), the gasification facility may be in proximity to biomass plantations to reduce biomass transportation costs and not 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 plantations, range from $10/MMBtu for larger projects to $30/MMBtu for smaller projects, due to pipeline extensions required to connect existing natural gas networks (Lowell & Jones, 2019). Adjusting these values to 2023$ and factoring in the capacity of the RNG-2 case specific to the East Coast results in interconnection costs of $14.5/MMBtu for RNG-2. Pipeline delivery costs for H_2 are discussed further in the next section.

Delivery Emissions

Based on the TEA modeling described above, H_2 compression requires approximately 0.562 kWh/kg, while liquefaction requires 9 kWh/kg. Using an East Coast grid-average emission factor of 287 kg CO_2e/MWh, the associated upstream electricity emissions are 0.2 kg CO_2e/kg for compression and 2.6 kg CO_2e/kg for liquefaction. Emissions from preparing and delivering H_2 to market were estimated by including all operational energy-related emissions but excluding truck embodied emissions associated with manufacturing delivery equipment. Pipeline embodied emissions are included because pipeline infrastructure is treated differently from discrete delivery equipment. However, these embodied pipeline emissions are represented using national-average construction and material data, not region-specific values. For consistency with the LCA goal and scope, regional variation is not applied to pipeline construction impacts.



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

Figure 40. Summary of national delivery GHG intensities in kg CO_2e/ kg H_2

For truck delivery, the TEA assumes a 120-km round trip. A liquid H_2 tanker is assumed to carry 3,500 kg, while a gaseous H_2 tube trailer carries 600 kg. Using the average GHG intensity for a U.S. diesel combination truck of 1.28×10^{-4} kg CO_2e/ ton-km (NREL 2023) the total ton-kilometers for the liquid and gaseous delivery cases are 420 and 72, respectively, leading to delivery-stage emissions of 0.05 kg CO_2e and 0.01 kg CO_2e (**Figure 44**). These values are relatively conservative as they do not account for the reduced mass during empty return trips; however, the effect is negligible given the small magnitudes. Embodied impacts from pressure-vessel production are also excluded.

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. 2022b). 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. From an emissions perspective, the single largest component of GHG intensity for delivery of H2 would be the estimated emissions of the on-site liquefier, at 5.4 kg CO2e/kg, which is comparable to the production emissions. The other components (compressor, truck delivery) would be generally small in comparison.

For liquid H_2 delivery, the largest contributor to the GHG intensity is the on-site liquefier with estimated emissions of 5.4 kg CO2e/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. 2024). 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. 2024).

End-Use Emissions

When evaluating alternative fuels, it is critical to recognize that no single fuel is a universal solution. The emissions reduction benefits and technical suitability for each end-use application vary significantly by supply chain context. For example, H_2 has strong potential in heavy-duty transportation and industrial heat due to its high energy content and zero direct CO_2 emissions at combustion with renewable-powered H_2 production offering the most promising results (Goita et al. 2025; Zhu et al. 2025a). Similarly, studies suggest that H_2 should only be used for hard-to-electrify sectors (e.g., industrial) as emissions reduction for end-uses such as buildings is minimal in comparison due to electrolytic H_2 production power requirements (Switchbox and EDF 2024).

While RNG is fully interchangeable with conventional natural gas and can be used with existing infrastructure for power generation, its potential emissions benefit hinges on feedstock type, methane leakage, and upgrading processes (Lim et al. 2025). Similarly, SNG can leverage power-to-gas and biomass pathways to produce methane compatible with current systems, but its emissions reduction benefits are contingent on the life-cycle performance of production pathways (Lee et al. 2024). These differences underscore that reducing emissions in one application does not guarantee similar benefits across other end uses or fuel types; upstream emissions (including methane leakage and production energy sources), infrastructure compatibility, and sector-specific performance must all be considered when comparing and deploying alternative fuels.

Power Generation Emissions

Substituting conventional natural gas with RNG offers measurable lifecycle GHG abatement potential for power generation; however, the extent of this benefit varies substantially by fuel pathway and upstream emissions performance. From DOE's natural gas baseline study, producing electricity from an NGCC F-class plant results in lifecycle GHG emissions of 467 kg CO2e/kWh, of which 61 kg CO_2e/kWh come from upstream natural gas emissions (Khutal et al. 2024a). In contrast, incorporating 90% carbon capture on a similar plant is estimated to reduce emissions to160 kg CO_2e/kWh, with 91 kg CO_2e/kWh attributed to upstream emissions. Despite lower total emissions, this configuration has higher upstream intensity due to additional energy required for the capture technology and CO_2 compression.

Using the same guidance as used in the cost section, this subsection assumes that there are no incremental activities needed on site to replace natural gas with SNG or RNG, and it leverages the U.S. average F-class NGCC values above, as well as the RNG and SNG values for the East Coast region. Thus, the only differences in estimating the emissions from end-use applications for these options are those associated with the upstream lifecycle emissions estimates. Using the U.S. average and East Coast regional emissions data presented above, **Figure 45** summarizes expected emissions for natural gas for power generation.

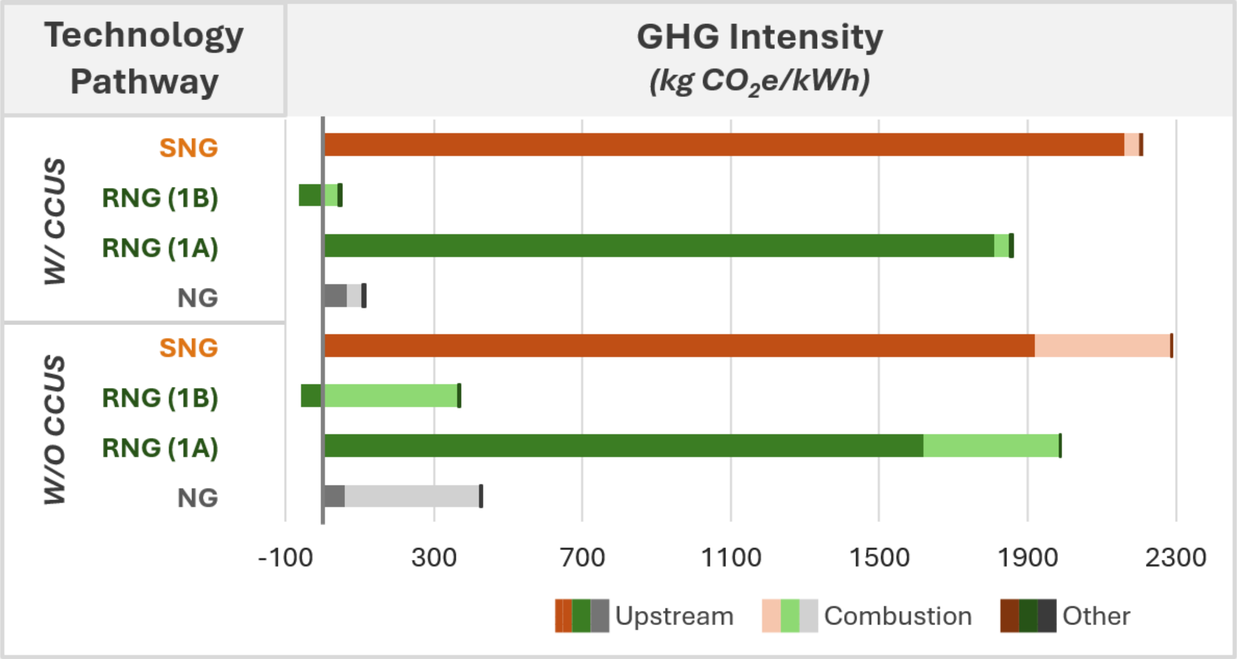


Figure 41. Expected emissions for natural gas power generation

RNG-1B is the only pathway that consistently achieves lower GHG intensity compared to natural gas-based power generation. These findings align with findings from Patel et al,: RNG from high-methane-emitting feedstocks (such as dairy manure or landfill gas) can achieve reductions exceeding 60–200 g CO_2e/MJ relative to fossil gas, depending on the baseline methane management scenario (Patel et al. 2025). Conversely, RNG produced from feedstocks with low counterfactual methane emissions, like in RNG-1A, does not yield emission reductions due to high upstream emissions. Similarly, the SNG fuel pathways evaluated rely on less advantageous feedstock sourcing, resulting in the high GHG intensities listed in **Figure 45**.

Although this section does not model H_2-based alternatives for power production, such pathways are currently being explored in the East Coast and show promising results. A notable example is the New York Power Authority (NYPA)'s Brentwood H_2 demonstration project, which successfully demonstrated the use of H_2 blends of up to 44% in a gas turbine (Larson 2023). This project highlights H_2's potential role in decarbonizing power generation. While NOx emissions have been a common concern with H_2 blending, the NYPA demonstration was able to maintain NOx emissions within permitted levels by utilizing selective catalytic reduction and water injection technologies. This demonstration project underscores that, with appropriate mitigation strategies, H_2 can be integrated by retrofitting existing systems and without compromising air quality standards.

Transportation Emissions

Heavy Duty Transportation

Substituting diesel with low-carbon alternative fuels in the heavy-duty trucking sector offers significant GHG abatement potential, but the scale of achievable reductions is highly pathway-dependent. Peer-reviewed LCAs of heavy-duty vehicles show that H_2 fuel-cell electric trucks (FCETs) powered by low-carbon H_2 can reduce well-to-wheel emissions by 70–90% relative to diesel. This offers the most significant well-to- wheel significant reductions relative to battery electric or LNG fueled trucks. In contrast, H_2 produced from natural gas or high-carbon electricity has the lowests emissions reduction potential and, in some cases, higher lifecycle emissions relative to diesel (Goita et al. 2025; Chhugani and Rahmani 2025). Although less commonly modeled or discussed, RNG- or SNG-fueled heavy-duty vehicles can similarly reduce emissions when supplied from high-value biogenic resources, but emissions benefits decline substantially for lower-quality feedstocks or when upstream methane leakage is not well controlled. Consequently, the abatement in heavy-duty trucking depends more on the carbon intensity of the fuel supply chain than on the vehicle itself.

Fuel transportation in this study considers transport from fuel production location to fuel use location. It is only modeled for H_2 as it is the most commercially prevalent. The GREET model has a significant database of U.S. average well-to-wheel values for various vehicle fuel pathways, as summarized in **Table 5** (NREL 2023). The transportation emissions are used in the "Transmission and Distribution" stage of well-to-wheels pathways for fuel production and use. **Figure 46** displays the GHG intensity contributions of different components of H_2 refueling station supply, delivery, and storage. Note that these values are for highway trucks but align well with other vehicle sizes. These results are consistent with previous studies highlighted above that conclude that electrolysis (with low-carbon power) provides the most significant opportunity for emissions reduction in transportation.

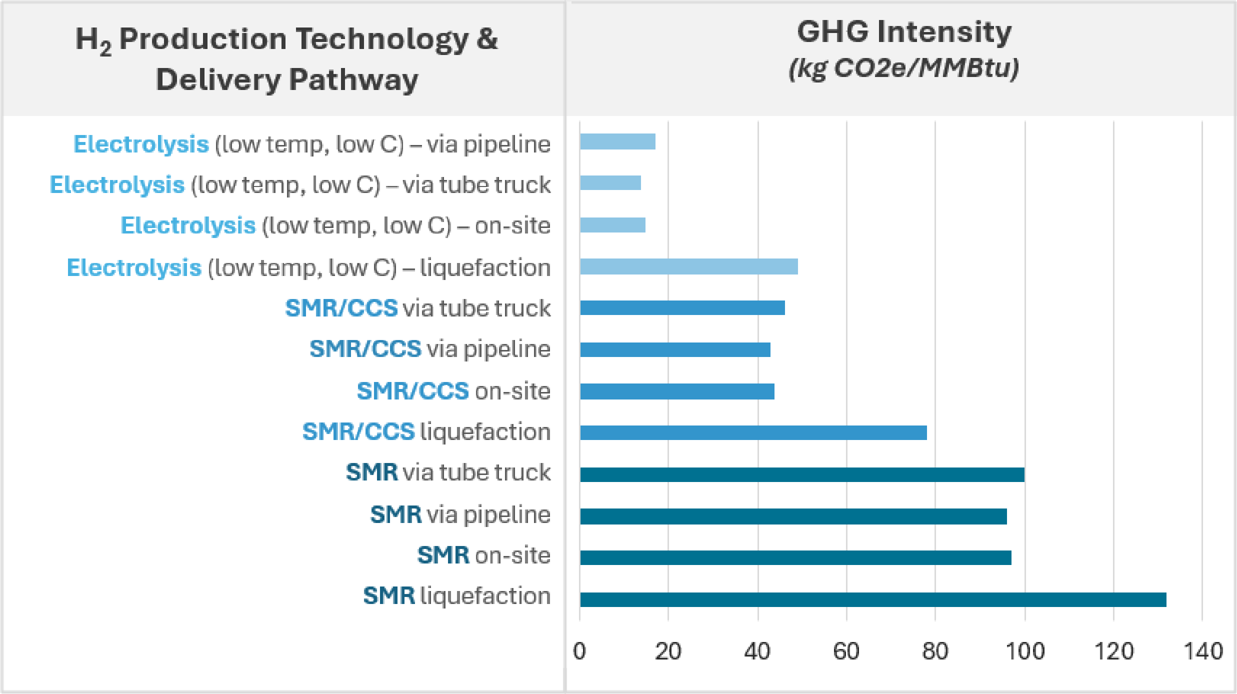


Figure 42. GHG intensity for various technology pathways related to transportation (U.S. average)

Industrial Emissions

The literature associated with decarbonization of heavy industry with H_2 is still growing. A recently published review summarizes estimates for various U.S. industries (Zhu et al. 2025b). The premise of most H_2 applications is to find high-thermal load processes where H_2 could be substituted either 1) for other existing fuels, or 2) where there are few available decarbonization options. For example, H_2 can be blended into the fuel of blast furnaces in place of carbon-rich fuels like natural gas, oil, coal, or coke. One estimate cites that such fuel displacement has the potential for 20% reduction in GHG emissions (Yilmaz et al. 2017). On the other hand, there are a few decarbonization options in ironmaking, but substituting low-carbon H_2 as the reductant in place of carbon monoxide or coke an reduce GHG emissions by 90% (Ramakgala & Danha, 2019). Crude oil refining and chemicals production could likely realize a 25% reduction in emissions, and methanol production could see a 12% reduction of emissions.

Meeting the local H_2 demand for these potential new consumption sources would likely require on-site electrolyzers. Additionally, reaching decarbonization targets might also depend on the availability of renewable electricity. Given the scale of iron and steel facilities, the electricity needed to power the electrolyzers could be significant.

Beyond high thermal load processes, a significant short-term opportunity for industrial use of H_2 is in the production of ammonia. The typical ammonia production process involves reacting natural gas with steam to produce H_2, which is then reacted with nitrogen separated from air, and is one of the largest GHG emissions sources in the global chemical industry. Ammonia itself is a versatile feedstock for various industries, the most significant being for fertilizers but could be fuel for vehicles or power generation. However, with a reliable and lower carbon source of H_2, the initial conventional step could be skipped, and it could be directly combined with nitrogen and lead to 85-95% emissions reductions (Mingolla et al. 2024; Mersch et al. 2024).

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% in their respective cases. All newly installed H_2 production is assumed to be low-carbon H_2, which includes blue H_2 (natural gas SMR with CCS) and green H_2 (electrolysis using renewable electricity. Gray H_2 (natural gas SMR without CCS) is not used.

The cost and performance data for low-carbon 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 10 vol% in their respective cases. All new RNG is assumed to be produced by MSW gasification and is blended 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 because the processed feedstock is biogenic. Emissions from blended NG delivered are, therefore, increasingly lower when more RNG is blended into the pipeline.

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% in their respective cases.
- 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.[5] Emissions from blended natural gas delivered are, therefore, increasingly lower when more SNG is blended into the pipeline.
- The emissions from each sector are also updated based on the CO2 captured to produce SNG, lowering the emissions further.

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[5] It is assumed that the CO_2 released during combustion offsets the CO_2 captured and utilized in its production.

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 OL-NEMS scenario results can be found in **Appendix H**.

Overall, total emissions decline across all scenarios over time, though the reduction is much smaller in the AEO23 and HM-HZTC cases and most pronounced in the Low OGS case. Power demand rises steadily each year through 2050 in every scenario. All cases show a consistent shift away from coal-based generation toward renewables, with total power capacity expanding annually to meet growing demand. Scenarios with higher renewable penetration require greater overall capacity additions because of the intermittent nature of renewable resources. Power prices generally fall in the early years through 2035, then rise after 2040, mirroring trends in Henry Hub natural gas prices, which decline through 2030 before increasing until 2040. After 2040, Henry Hub prices drop in most cases except the BAU side cases and the LowC H2 20 vol% scenario. Delivered natural gas prices trend lower in the power and transportation sectors across all scenarios, while remaining stable or slightly rising in commercial, industrial, and residential sectors. Natural gas consumption decreases in the early years but declines less sharply in the HM-HZTC and SNG 20 vol% scenarios, both of which ultimately show a net increase in consumption by 2050. Shale gas production dominates in all scenarios and reaches its highest level in the HM-HZTC case.

For H_2, prices remain stable across most years except in the LowC H2 and SNG scenarios. In both RNG scenarios, prices rise slightly in the early years and continue to increase modestly later, while in the SNG scenarios, prices start with a slight upward trend but escalate sharply in later years. In the AEO23 Reference case, coal generation and capacity persist through 2050, unlike other scenarios where coal is nearly phased out. Broader energy trends in this case remain closer to historical projections rather than the transformative shifts seen in alternative scenarios.

The Low OGS scenario achieves the lowest emissions by 2035 due to reduced energy availability and slower macroeconomic growth. LNG exports and total natural gas consumption are also at their lowest levels, and shale gas production does not increase as it does in other cases. Henry Hub spot prices and delivered natural gas prices are higher in this scenario, resulting in elevated energy costs. In the SNG scenarios, particularly SNG 20 vol%, power generation and capacity expand significantly (primarily through renewables), matching other alternative scenarios except AEO23 and Low OGS by 2035. Coal power is nearly eliminated, and natural gas demand in the power sector is lower in 2035, which keeps natural gas prices slightly lower initially, though they rise later. H_2 demand surges because it is essential for SNG production via electrolysis, driving sharp increases in power sales to H_2 and making total power sales highest in this scenario by 2035. SNG production scales with blending levels, and in the 20% scenario, additional SNG is required to meet growing natural gas demand. However, SNG prices climb steeply after the expiration of 45Q credits, surpassing $100/MMBtu (2023$) by 2040.

The LowC H2 scenarios exhibit high H_2 demand due to blending requirements, with production primarily from SMR/ATR with CCS. This transition reduces natural gas use in the industrial sector as H_2 displaces it. H_2 prices rise significantly, reaching over $25/MMBtu (2023$) by 2035. In the RNG scenarios, RNG production scales with blending levels but remains costly compared to other H_2 production methods. H_2 is not produced from RNG in any scenario.

Current State of Infrastructure

The East Coast has relatively limited natural gas production, with notable exceptions in Pennsylvania and West Virginia. These states serve as key contributors largely due to their substantial industrial base and proximity to the Marcellus and Utica shale formations, which are among the most productive natural gas regions in the United States. As illustrated in **Figure 47**, the natural gas infrastructure in this area reflects these concentrated production zones.

To optimize these resources, several natural gas market hubs are strategically located throughout the region, facilitating distribution and trading activities. However, the southern portion of the East Coast (particularly states such as the Carolinas and Georgia) tends to rely more heavily on supply from neighboring Gulf Coast states. This dynamic creates a strong interregional dependency, where the East Coast’s energy security and pricing are influenced by the Gulf Coast.

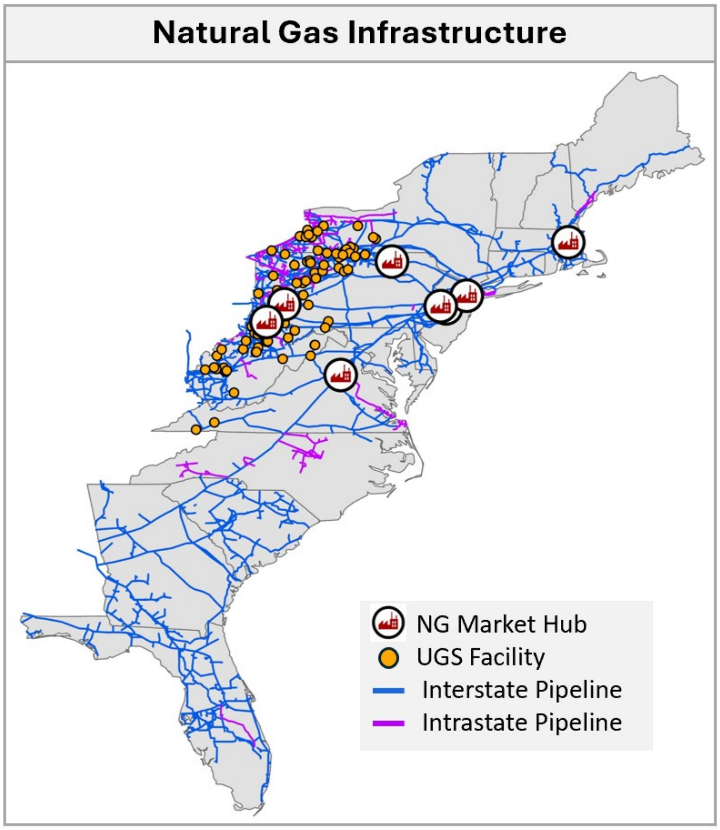


Figure 43. Natural gas infrastructure in the East Coast

Natural gas infrastructure continues to evolve in the region, with multiple planned expansions and upgrades in progress, and new pipeline construction projects occurring. As of October 2025, two major projects have expanded natural gas pipeline infrastructure along the East Coast this year: Alabama Georgia Connector Project in Georgia, which added 34 MMCFD of capacity, and Eastern Panhandle Expansion Project, a lateral pipeline from Pennsylvania to West Virginia, which added 48 MMCFD of capacity. In addition, three more projects in Virginia and North Carolina are scheduled for completion by year-end, collectively adding 205 MMSCFD of capacity. Looking ahead, 22 additional pipeline expansion and new construction projects have been announced, representing a planned increase of 11,349 MMCFD in regional capacity (EIA 2025a). **Figure 48** below highlights the investments announced in 2025 to increase natural gas capacity across the East Coast. Additional expansion projects like the pending Tioga Pathway Project are intended to increase the transportation capacity of gas supply from the Appalachian basin into the interstate pipeline grid in Pennsylvania

(National Fuel 2026). If approved by FERC, this project will construct 19.5 new miles of pipeline in 2026 to enhance the reliability of natural gas supply in the region.

These developments underscore the critical role East Coast pipelines play in enhancing energy reliability and accessibility. Furthermore, they present opportunities to adapt existing infrastructure for the delivery of low-carbon fuels, supporting long-term decarbonization goals while meeting growing energy demand.

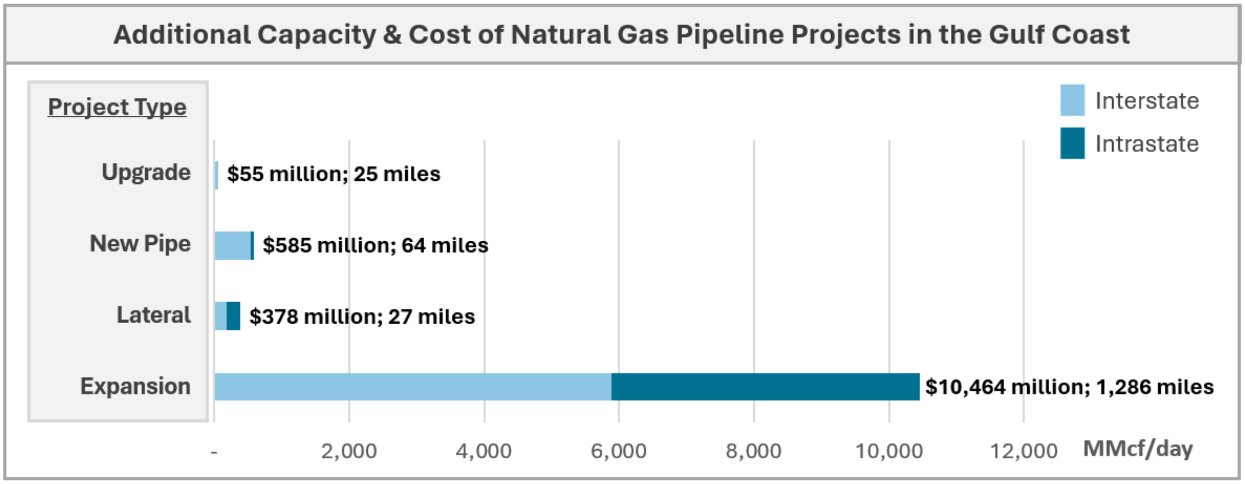


Figure 44. Additional capacity from announced natural gas pipeline projects for the East Coast (October 2025) (Energy Information Administration 2025)

Figure 49 below summarizes the current and proposed H_2 and CO_2 infrastructure in the U.S., along with assessed total available CO_2 (PHMSA, Pipeline Mileage and Facilities, 2024). At present, there are no existing or planned H_2 or CO_2 pipelines in the East Coast. Additional CO_2 pipeline developments, especially in the vicinity of existing natural gas storage sites and saline storage can support low-carbon H_2 production through carbon capture and storage.

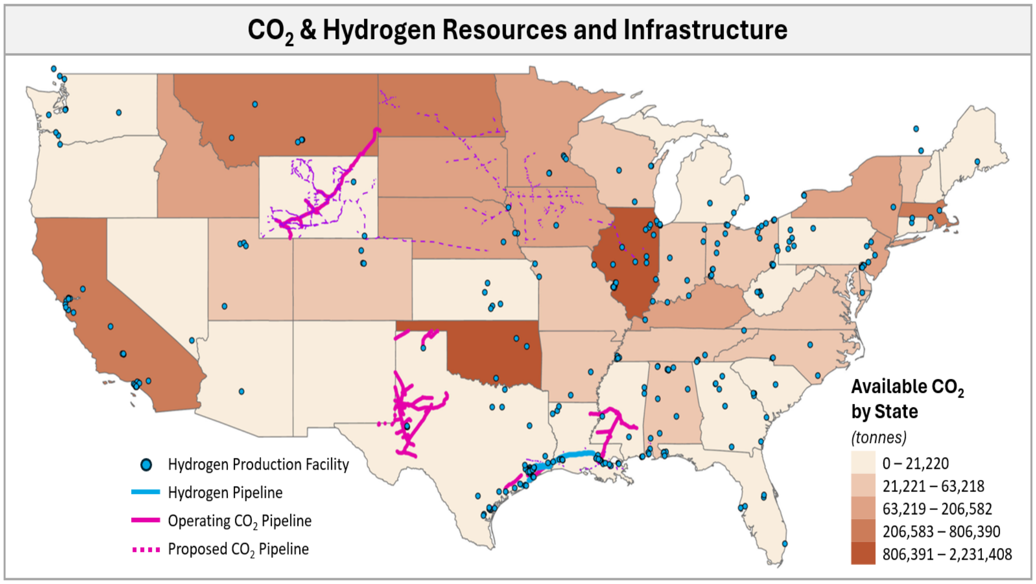
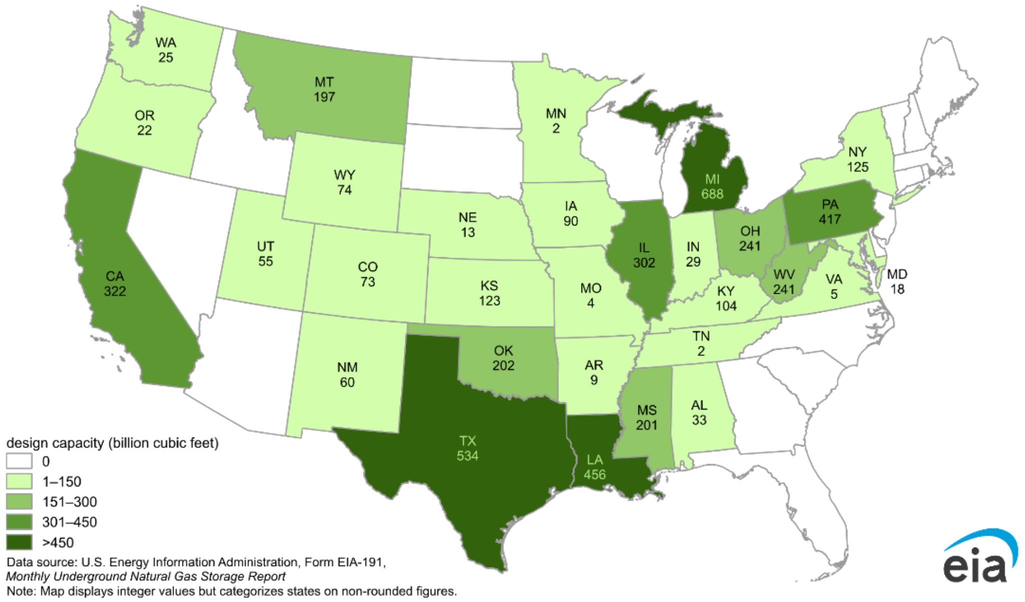


Figure 45. Existing and proposed H_2 and CO_2 infrastructure by state (PHMSA, 2024)

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.



Data source: U.S. Energy Information Administration, Form EIA-191, *Monthly Underground Natural Gas Storage Report*
Note: Map displays integer values but categorizes states on non-rounded figures.

Figure 46. Design working natural gas capacity by state in November 2023; Source: (U.S. Energy Information Administration, n.d.)

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.

UGS plays a vital role in the East Coast’s energy system, despite being concentrated in only five of the region’s 17 states. Pennsylvania leads with the highest working gas capacity (418 BCF) and deliverability (9476 MMSCF/day), followed by New York and West Virginia. Pennsylvania alone accounts for 60% of the region’s deliverability, reflecting its strategic importance. The region contains 102 UGS facilities, two salt caverns, two aquifers, and 98 depleted fields, making up 27% of the national total. However, UGS infrastructure is primarily located in the northern half of the East Coast, leaving the southern states and New England dependent on long-distance pipelines from the Appalachian Basin and Gulf Coast to meet their gas needs, especially during winter peaks.

The region faces multiple challenges in expanding UGS, including regulatory complexity, infrastructure constraints, and siting concerns near residential areas. Many East Coast states lack comprehensive UGS regulatory frameworks due to the absence of facilities in their territories. In states that do have UGS, permitting typically requires rigorous compliance with safety, environmental, and operational standards to ensure public safety and prevent gas leaks or water contamination. Despite these hurdles, UGS remains a cornerstone of the East Coast's energy reliability and resilience and is expected to continue playing a key role in the transition toward a more sustainable energy future. Additional regulatory details are available in the RAISE report, *Underground Gas Storage in Natural Gas Infrastructure: East Coast Insights*.

Access to underground storage facilities can support the storage of low-carbon fuels like H_2 and help integrate renewable energy by providing long-term, flexible storage solutions. 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.

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 CO_2 in UGS operations.

Most Promising Pathways Excluding CCS

Developing CCS infrastructure may be impractical in certain East Coast subregions that lack proximity to suitable geologic storage sites. **Figure 51** highlights H_2 fuel pathways with the lowest required incentives that do not rely on CCS. For nine states in the region, H_2 produced via natural gas plasma pyrolysis offers the lowest incentive requirements when excluding CCS-based options (such as NG SMR with CCS and NG ATR with CCS). Although NG SMR with CCS and NG ATR with CCS show lower calculated costs, pathways that avoid CCS infrastructure may be more optimal for some East Coast locations.

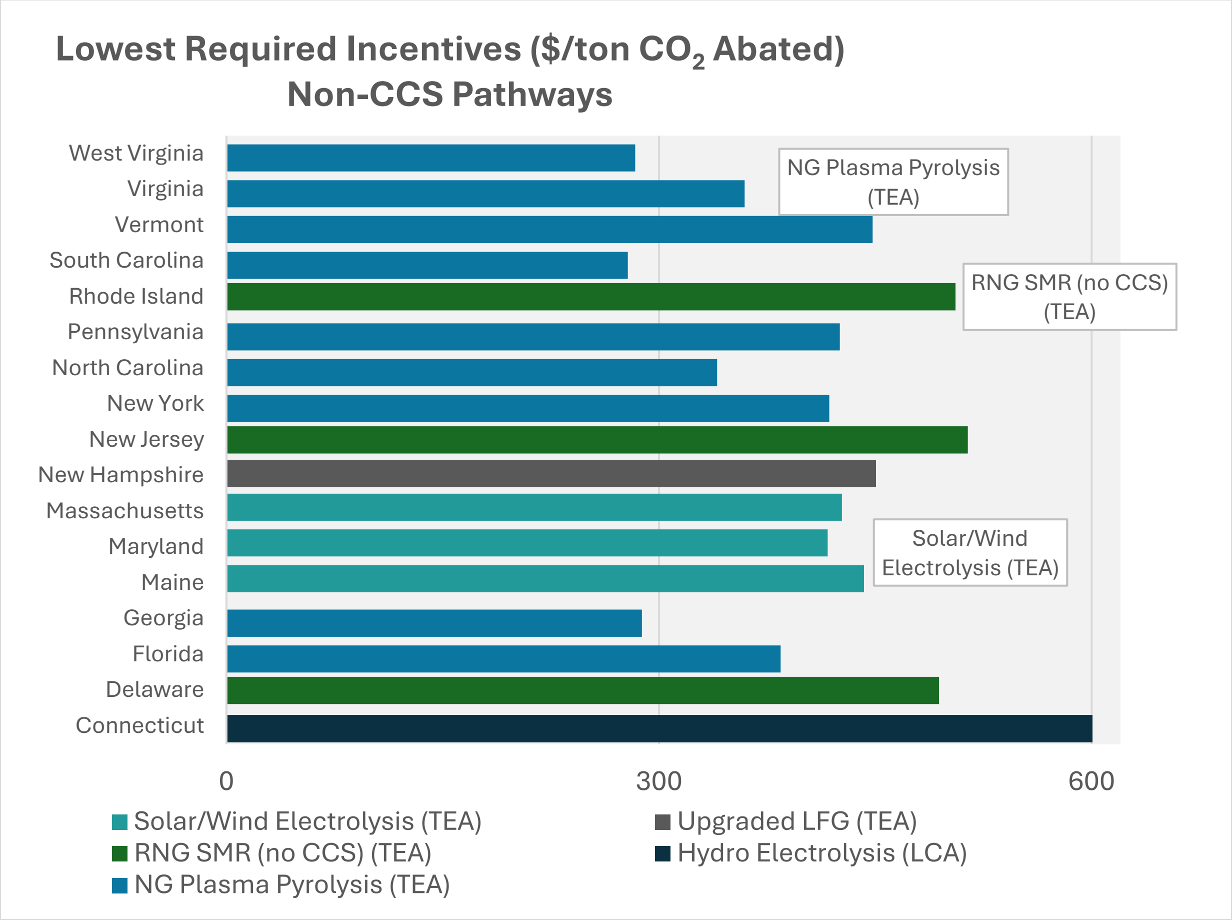


Figure 47. Lowest required incentives for pathways excluding CCS

Renewable Energy Availability

Reliable energy systems deliver fuel to customers with minimal interruptions and high efficiency. On the East Coast, energy reliability is heavily influenced by dependence on electric infrastructure, where unexpected maintenance on electric transmission lines can lead to service disruptions for end users. Natural gas distribution networks deliver fuel to gas-fired power plants to meet most of this electricity demand in the East Coast. High pipeline utilization reflects the system's flexibility and ability to meet peak demand, serving as an essential buffer during periods of electric grid stress. By integrating high-deliverability natural gas with the electricity grid, the East Coast can strengthen overall energy reliability and better accommodate rising demand.

Regional Energy Consumption

Significant in-state energy production is a critical factor in ensuring energy reliability. **Figure 52** highlights key statistics regarding energy consumption across subregions. Subregions 1B and 1C (New York, Pennsylvania, New Jersey, Delaware, Maryland, West Virginia, Virginia, North Carolina, South Carolina, Georgia, and Florida) generally exhibit lower ratios of total energy consumption relative to in-state production. In contrast, Subregion 1A states (Maine, Vermont, New Hampshire, Connecticut, and Rhode Island) have higher consumption-to-production ratios, making them prime candidates for scaling emerging fuels to enhance future energy reliability.

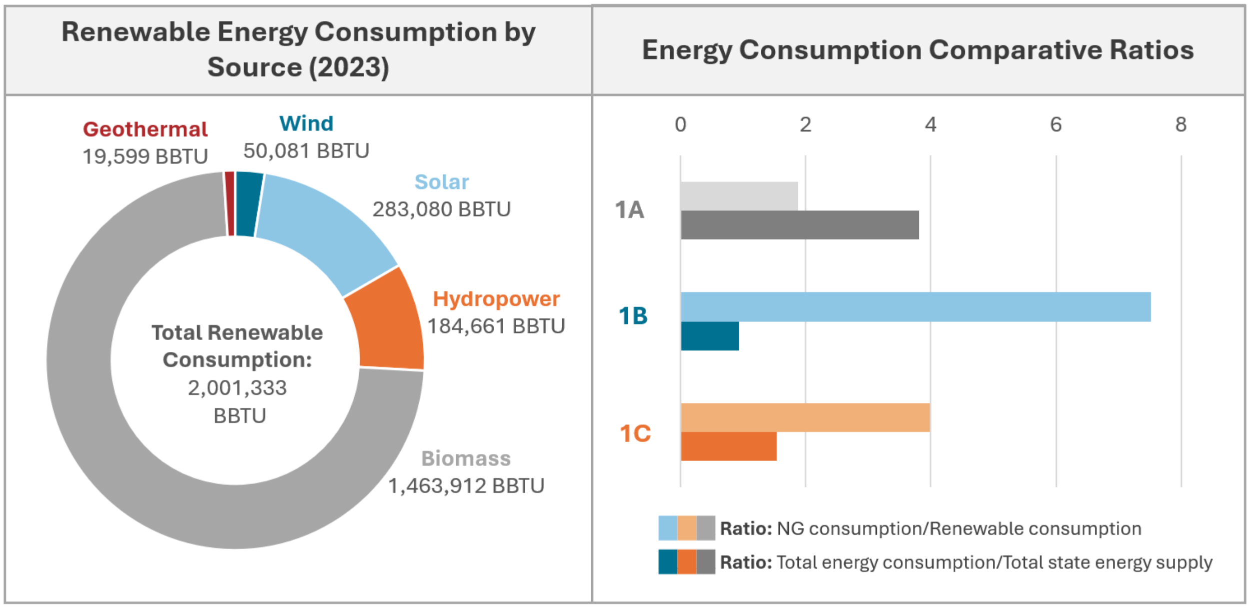


Figure 48. Energy consumption statistics by subregion (EIA, 2024)

Energy Disruptions and Weather Impacts

Extreme weather events on the East Coast pose significant risks to the reliability of energy systems, making weatherization of both electric and natural gas infrastructure a critical priority. These events can lead to widespread outages and life-threatening shortages of electricity, heating, and other essential services, particularly during periods of peak demand. **Figure 53** illustrates the extent of damages by state caused by severe weather events, highlighting the vulnerability of existing infrastructure. Beyond the operational risks, these disasters impose substantial financial burdens, with billion-dollar losses across multiple states. This underscores the urgent need to strengthen and weatherize key components of the energy supply chain to enhance resilience, protect public safety, and mitigate economic impacts.

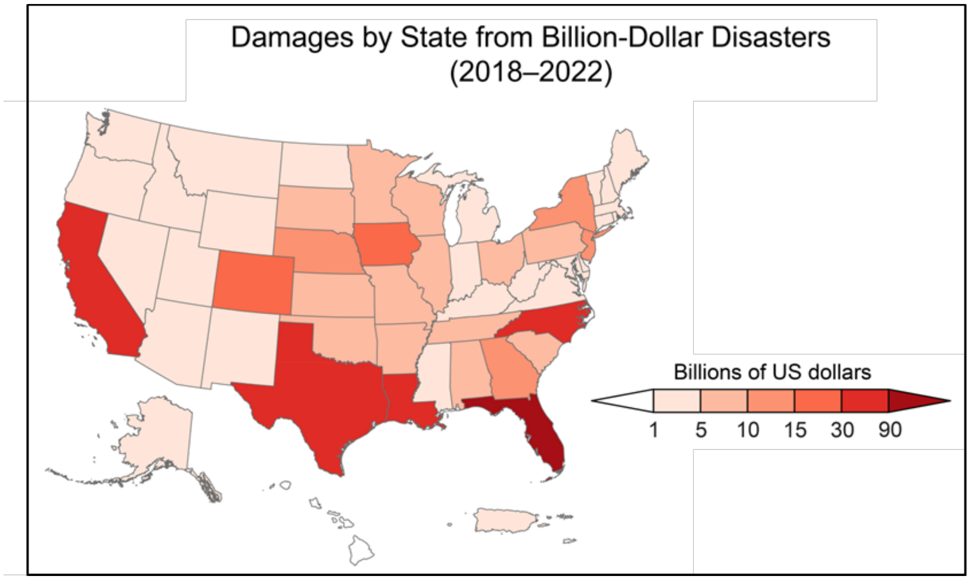


Figure 49. Damages by state from billion-dollar disasters (e.g., winter storms, droughts, floods, or wildfires); Source: (Fifth National Climate Assessment 2023)

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

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

As part of a broader resilience strategy, attention is increasingly focused on UGS and enabling end users to access multiple fuel options. UGS strengthens system reliability by supporting rapid responses to supply-chain disruptions or sudden shifts in supply and demand. On the East Coast, UGS capacity is essential for adapting quickly to such events, ensuring a stable natural gas supply even during extreme weather. This role becomes more critical as climate change intensifies risks across interconnected sectors and regions. In addition to seasonal variability, the East Coast is projected to experience rising energy needs over time to adapt to climate impacts, as illustrated in **Figure 54**.

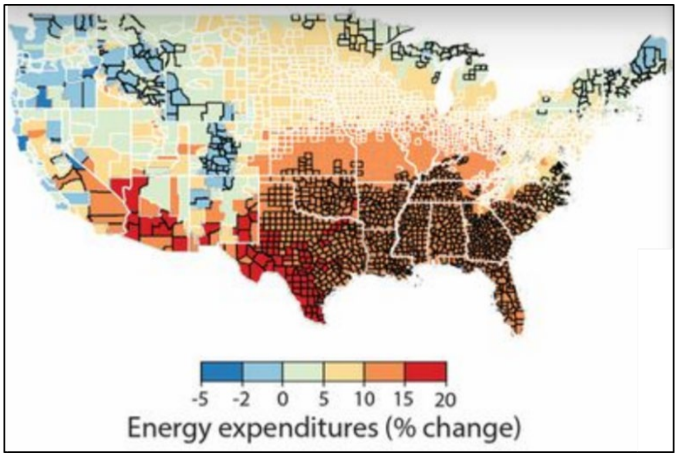


Figure 50. County-level median values for average 2080 to 2099 RCP8.5 impacts. Source: (Hsiang et al. 2017)

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). The acceptable blend percentage will need to be determined based on the integrity and operating pressure of the pipeline system.

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 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 and the acceptable blend percentage.

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).

System Capacity Considerations

While RNG and SNG have energy content comparable to fossil-based natural gas, H_2 has approximately one-third the energy content 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 9 times less dense than natural gas and requires approximately 3 times the compression power), 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). Therefore, 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.

Impacts of Pipe Materials on System Capacities

Replacement of bare steel and cast iron distribution pipe also has implications for system capacity availability for H_2, RNG and SNG. Cast iron is not suitable for H_2 service, while bare steel, for instance, is known to have declining pipe wall thickness over time, which proportionally reduces calculated design pressures of a pipe segment. Maximum allowable operating pressures (MAOPs) for aging pipes are required to be lower compared to modern steel and PE pipe materials, thus reducing the system capacities of distribution systems with higher rates of bare steel mains and services. Additionally, the location of natural gas distribution pipe segments influences the allowable design pressures. For example, under Federal Title 49 § 192.111, stricter design factors apply to steel pipelines located near densely populated areas.

East Coast Pipeline Material Trends

Knowledge of remaining cast iron and bare steel pipe locations is a critical consideration for scaling H_2, RNG, SNG blends in the East Coast. The following sections discuss the progress of cast iron and bare steel pipeline replacements for natural gas distribution mains and services.

PADD 1a Cast Iron and Bare Steel Inventories

New England states have the highest percentage of cast iron in the U.S., particularly in distribution mains. In contrast, bare steel is more prevalent in New England distribution service lines. States such as Maine and Connecticut have more miles of cast iron and bare steel that must be replaced to achieve full system modernization of natural gas distribution networks, requiring more investments. **Figure 55** summarizes cast iron and bare steel remaining in natural gas distribution networks in the PADD 1a region states.

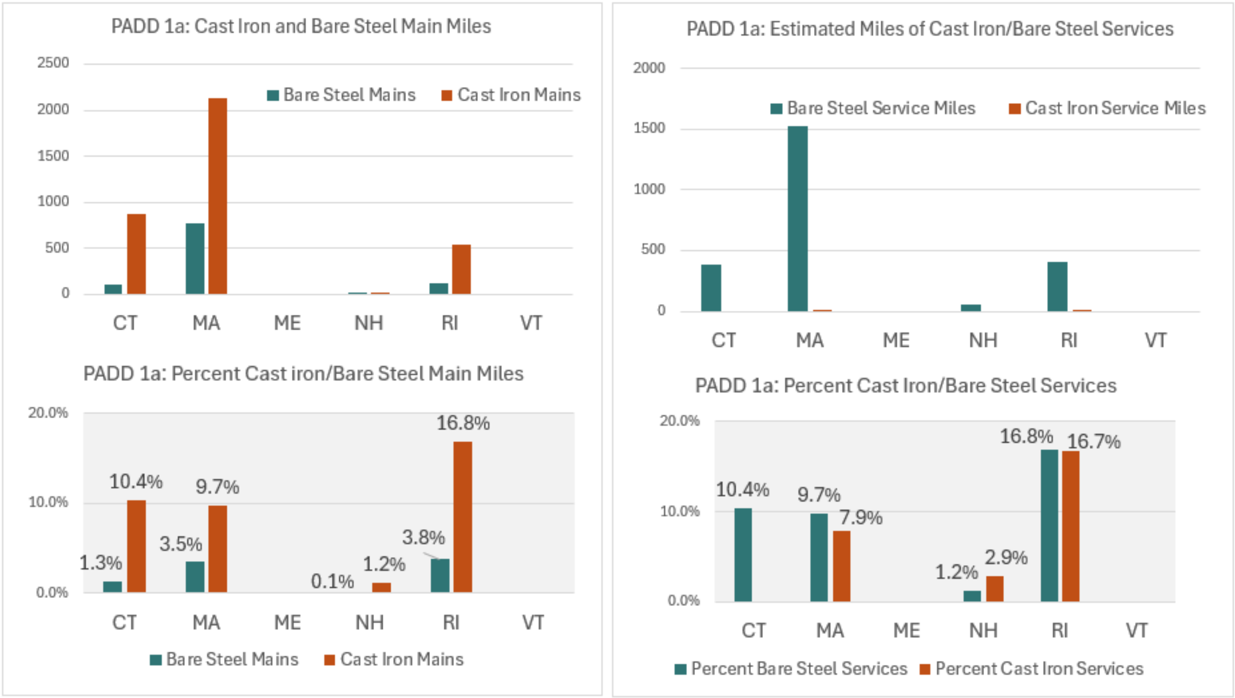


Figure 51. Summarized cast/ductile iron and bare steel distribution pipeline inventories in PADD 1a: Central Atlantic

Lengths of bare steel and cast-iron service pipe are estimated with average PHMSA reported service lengths by state. Note that New England states demonstrate similar average service lengths in PHMSA reported data.

States with smaller natural gas distribution networks, such as Rhode Island and New Hampshire, will likely require more near-term pipeline replacements to enable scaling of emerging fuels.

Miles of cast/ductile iron and bare steel services are calculated using PHMSA reported service average lengths and percentage represented by service count by state. Due to Massachusetts's larger average service length compared to other states in the region, a higher estimated number of miles of bare steel services will likely require replacement compared to other states in the region.

PADD 1b Cast Iron and Bare Steel Inventories

Similar to the New England subregion, the Central Atlantic has relatively high rates of cast iron and bare steel remaining in natural gas distribution systems (**Figure 56**). Maryland, New York, and Pennsylvania possess similar amounts of cast iron and bare steel mains.

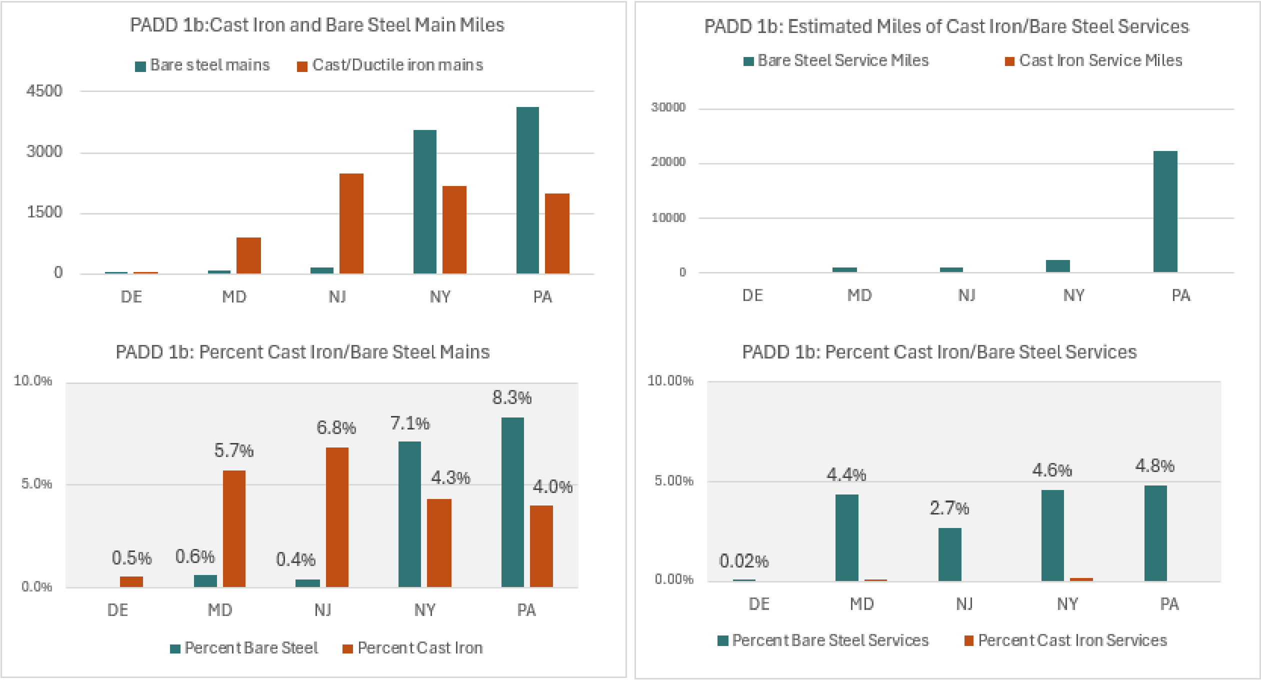


Figure 52. Summarized cast/ductile iron and bare steel distribution pipeline inventories in PADD 1b: Central Atlantic

Central Atlantic states demonstrate similar average service lengths in PHMSA reported data, with Pennsylvania as a notable outlier. Its average service length exceeds other states by multiple orders of magnitude. Consequently, Pennsylvania is estimated to have the greatest mileage of bare steel services, despite having similar bare steel service counts to New York and Maryland. These longer service lengths increase replacement costs and may also extend timelines for replacing bare steel and cast iron services.

PADD 1c Cast Iron and Bare Steel Inventories

The Lower Atlantic region has the lowest rates of remaining cast iron and bare steel pipe in natural gas distribution systems of all East coast subregions, with the exception of West Virginia (**Figure 57**). In most PADD 1c states, quantities of remaining cast iron are near zero (<1% mains and services). However, higher rates of bare steel mains and service pipe are still in service in Florida and West Virginia.

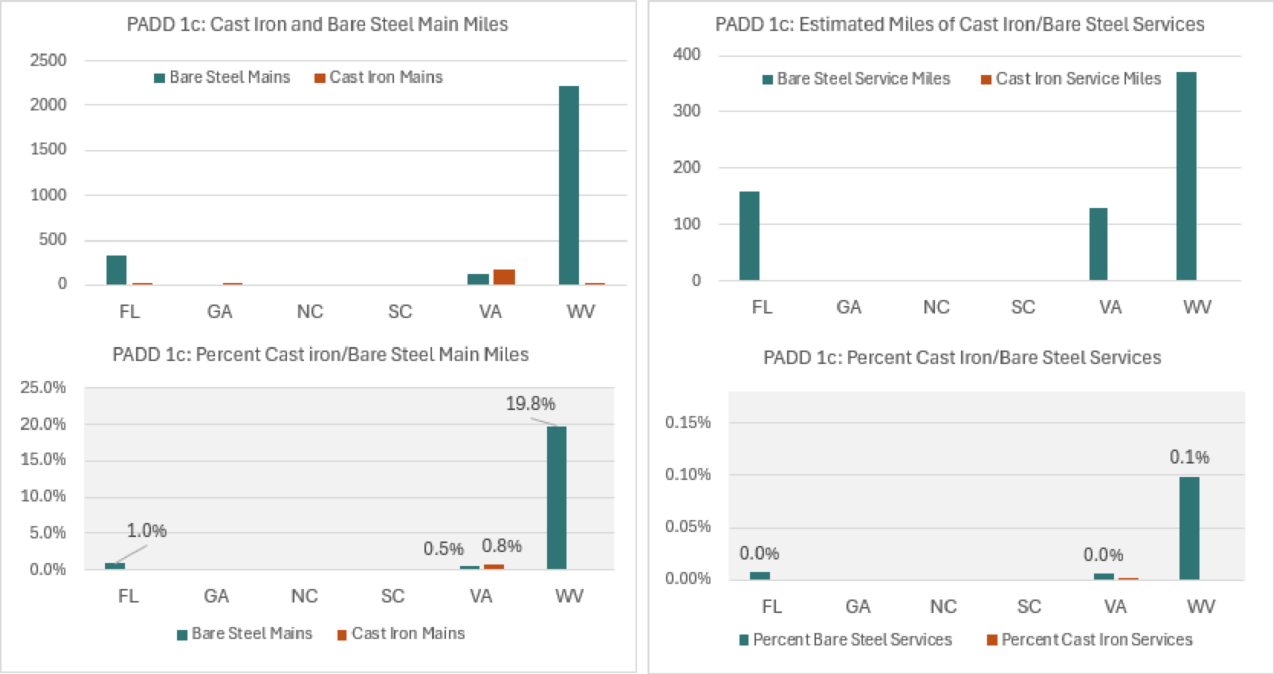


Figure 53. Summarized cast/ductile iron and bare steel distribution pipeline inventories in PADD 1c: Lower Atlantic

Lower Atlantic states generally have similar estimated average service lengths, with West Virginia as a notable exception. PHMSA reported average service lengths in West Virginia are nearly half that of other states in the Central Atlantic subregion. However, bare steel services in West Virginia account for less than 1% of total service counts, indicating a relatively small number of system end users.

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, 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 10** visualizes natural gas consumption in the East Coast region for residential, commercial, and industrial sectors. Commercial and residential natural gas consumption on the East Coast is closely aligned across most counties, positioning the region as an early adopter of higher H_2 blends. Research on residential end-use equipment indicates that most combustion appliances can accommodate blends up to 20 vol% H_2, though some will require retrofits for higher concentrations. Industrial natural gas users are more dispersed, with highly varied applications across the region. To address these heterogeneous requirements, H_2 deblending stations can be strategically located where end-use specifications differ significantly.

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[6], malfunction or degradation of burners, reduced heat transfer, and increased moisture content or NOx emissions.

Table 7 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
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	Liquefier	0.1 (American Gas Association 2013)	Partial liquefaction, reforming chemistry

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

Chemicals Manufacturing			
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.

Project Highlights in the East Coast

Natural gas pipeline projects exhibit variability in both cost and completion timelines due to regional factors. This section summarizes examples from the East Coast to assess the range of costs, project schedules, and challenges encountered by different operators. **Table 8** summarizes example cost differences for natural gas transmission installation costs for low and high accessibility cases. Regional topography can create additional challenges and thus increase associated costs to install natural gas pipelines.

Table 5. Example natural gas transmission installation costs by accessibility level

Transmission Pipe Installation Accessibility Description	Installation cost
Higher accessibility case: Flatter topography reduces excavation/grading, but higher right-of-way acquisition costs in developed areas, wetlands mitigation	\$5-10 million per mile
Lower accessibility case: Steep slopes, limited access roads, extensive rock excavation, stream crossings	\$8-18 million per mile
Difference:	\$3-8 million per mile

For instance, lower installation costs are observed for pipe installations in graded areas with easier access; however, right-of-way acquisition costs can increase in regions containing wetlands.

Figure 58 illustrates the variation in installation costs for distribution mains across rural, urban, and suburban settings for both protected steel and plastic mains. Natural gas main pipeline replacement costs tend to be higher in urban areas compared to rural or suburban locations. Local distribution companies must also decide between using polyethylene pipeline materials or protected steel, the latter generally being more expensive.

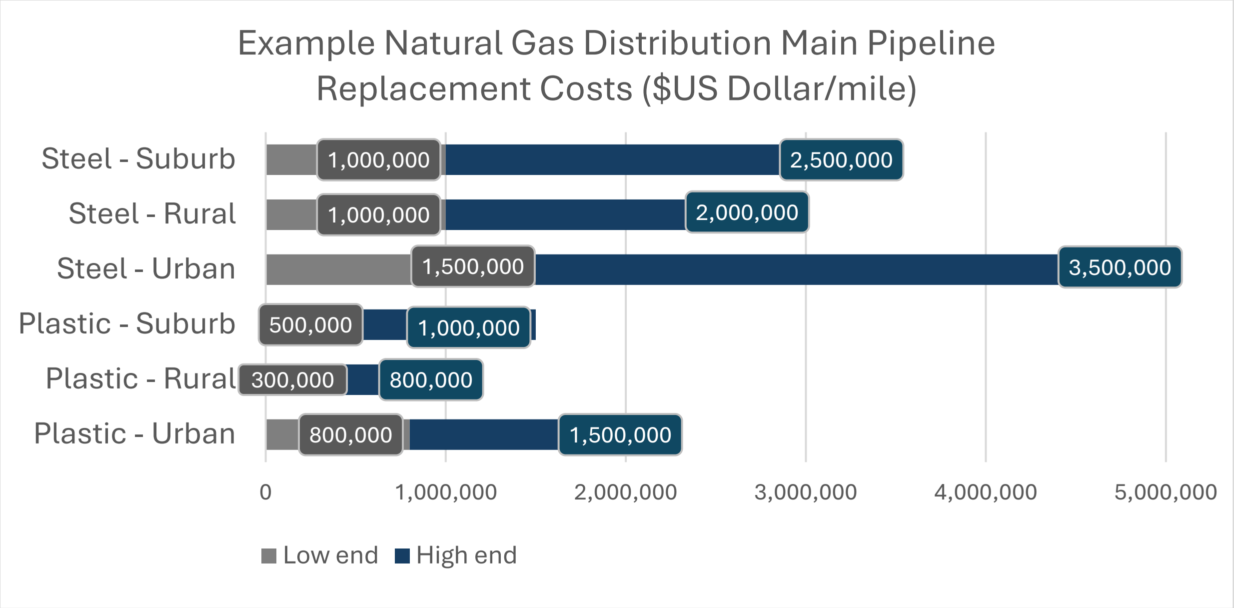


Figure 54. Example natural gas distribution pipeline replacement costs ($/mile)

Table 8 presents approval timeline ranges for replacing natural gas distribution mains in two states, based on data provided by local distribution companies. Extended replacement timelines are primarily driven by local geographic constraints and permitting requirements, which vary according to regional regulatory oversight.

Table 6. Example East Coast approval timelines for natural gas distribution pipelines

Natural Gas Distribution Location	Simple case:	Complex case:

	Routing replacements under blanket authority	Replacements requiring individual permits
State 1	9-18 months	12-24 months
State 2	6-15 months	9-18 months

H_2 Pipeline Costs and Timelines

Along with differences in costs, permitting and construction timelines also vary for H_2 pipeline developments. **Table 9** and **Table 10** present example project timelines for developing new H_2 distribution pipelines and for integrating H_2 into existing natural gas networks. Key factors influencing these timelines include permitting requirements across jurisdictions, the type and number of end users for H_2 blends, and local construction challenges. **Table 10** highlights example timelines for implementing new low H_2 blends (up to 10%) into natural gas systems in comparison to timelines for higher H_2 blends (15-25%).

Table 7. Example East Coast permitting and construction timelines for new H_2 pipelines

H2 Distribution	Total Timeline	Permitting	Construction
State 1	2–3 years	9-15 months	12-18 months
State 2	3–5 years	15-30 months	12-18 months

Table 8. Example East Coast timelines for H_2 repurposing of natural gas distribution pipelines

Timelines for H2 Pipeline Blending into Natural Gas Distribution Pipe	
Materials Assessment Phase	6 -12 months
Low-blend implementation (5–10%)	9 -18 months
Total timeline – Low blend (5-10 %)	12 – 30 months

Higher-blend implementation (15–25%)	18 - 30 months
Total timeline – High blend (15 – 25%)	33 – 60 months

The example timelines for implementing H_2 blends show that higher H_2 blends are expected to take about double the time to be established in a specific natural gas system. These ranges of expected timelines occur as a result of system-specific materials, end use assessments and permitting requirement differences. These timelines underscore the importance of pipeline replacements and location-specific permitting considerations in the decision-making process for scaling H_2 blends in natural gas distribution systems.

Example RNG Interconnection Costs and Timelines

Figure 59 illustrates example costs and timelines for RNG production co-located with three facility types: a wastewater treatment plant, an agricultural manure facility, and an MSW landfill in the East Coast. Among these examples, total interconnection costs tend to be higher for MSW landfill RNG projects in urban or suburban areas compared to those for rural wastewater treatment plants. However, this trend does not extend to construction costs, which remain relatively similar across MSW landfill, wastewater treatment, and agricultural RNG facilities.

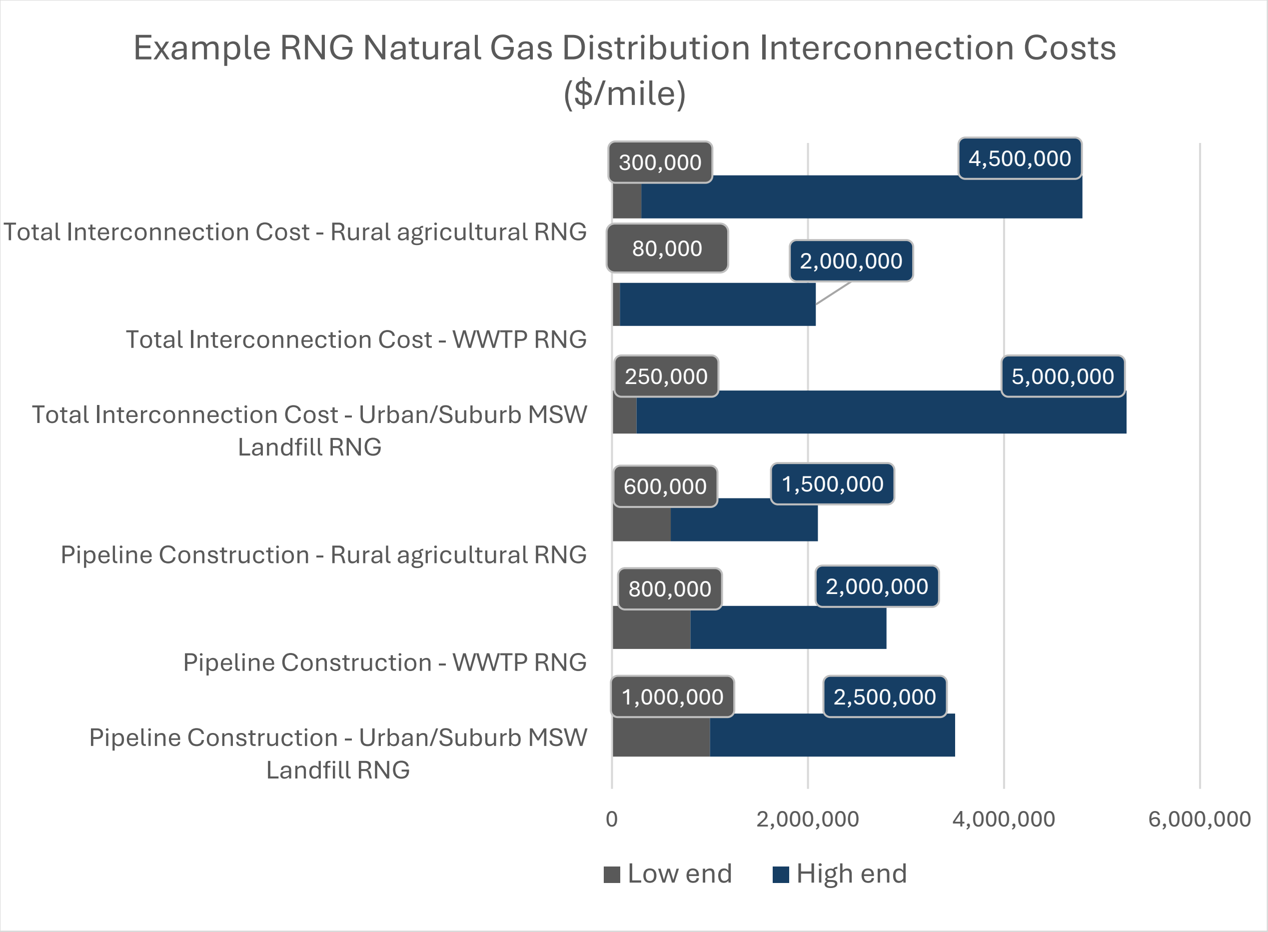


Figure 55. Example natural gas interconnection with RNG production facility costs ($/mile)

Cost Comparison of New and Retrofitted 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. As discussed in the **Project Highlights in the East Coast** section, a new natural gas pipeline in the East Coast region can cost $5-18 million per mile. Applying the upper end of the EPRI estimate to this range, a new H_2 pipeline in the East Coast could potentially cost between $5.1 and 18.9 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. Using the upper end of this estimate, repurposing a pipeline on the East Coast could range from approximately $510,000 to $6.7 million per mile.

When comparing new construction and retrofit options, the financial case for repurposing existing infrastructure is evident. Repurposing infrastructure provides the opportunity to avoid right-of-way acquisition logistics, reduce construction emissions, and fast-track project timelines.

If RNG becomes the primary decarbonization pathway for the East Coast region, no significant design modifications will be needed as it is chemically indistinguishable from conventional natural gas. However, operators will need to ensure that the RNG meets gas 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 11** summarizes the agencies that 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, whether used for the geological storage of natural gas or CO_2, 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 and not facility design, operation, or maintenance. For safety regulation of UGS 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. The EPA regulates the permitting of injection wells through the Underground Injection Control Program, including wells used in natural gas underground storage operations (Class II) and wells used for the geological storage of CO_2 (Class VI). States must apply to the EPA for primacy enforcement authority for well classes they wish to oversee, otherwise oversight remains with the federal agency.

Table 9. 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	Oversees facilities owned by interstate pipeline companies or independent operators engaged in

	and sets conditions for pipeline construction, including sitting. Sets maximum rates for interstate pipeline transportation services.	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 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 pipelines must get approval from all the state authorities through which their proposed H_2 pipeline would cross. This is also the case for the siting and permitting of interstate CO_2 pipelines, though the regulation of safe construction and operation of CO_2 pipelines remains with PHMSA (Carbon Capture Coalition 2025). While this process has been adequate for building the current H_2 and CO_2 systems, it may be prudent to institute federal regulations and standardized processes for interstate pipeline sitting and permitting as larger 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 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 SMR 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 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). Although 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 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. 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 emerging fuels. This is essential to ensure that, during the long-term transition between gaseous fuels, the appropriate authority can establish and enforce developmental, operational, and safety standards for the safe large-scale use of H_2 and its blends (*U.S. National Clean Hydrogen Strategy and Roadmap*, n.d.).

Table 10. 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

East Coast Landscape

Natural Gas Infrastructure & Industry

States across the East Coast Region are prioritizing the modernization of gas systems by replacing aging, leak-prone pipelines to improve safety and reduce methane emissions. Many states have legislation and programs in place to accelerate the replacement of these pipes which frequently include cost-recovery mechanisms. Pennsylvania's Act 11 of 2012, for example, authorized a Distribution System Improvement Charge (DSIC) enabling utilities to recover costs for accelerated pipeline upgrades under 5-year infrastructure plans. Similarly, Maryland's 2013 STRIDE law allows surcharges to fund pipeline replacements while a 2025 Ratepayer Protection Act now requires prioritizing high-risk pipelines and considering non-pipe alternatives to control costs. New Jersey and Virginia also have large modernization efforts, with PSE&G's Gas System Modernization Program (GSMP) replacing 875 miles of cast iron and unprotected steel mains in New Jersey and Virginia's SAVE Act program replacing hundreds of miles of old mains. In the Southeast, utilities like Florida's FPUC are executing programs such as the GUARD initiative to replace over 90 miles of leak-prone pipelines with modern materials.

States in the northern and southern regions of the East Coast differ in their long-term vision for natural gas and the role it will play in their future energy systems (**Figure 60** and **Table 13**). Northern states, such as New York, Massachusetts, Connecticut, and Rhode Island, have put forth policies that could reduce the role of gas in their energy systems. These states are introducing measures to limit system expansion, redirect investments toward electrification, and explore non-pipeline alternatives. For example, New York's NY HEAT Act repealed the "100-foot rule" for gas main extensions and mandates a statewide transition plan, while Massachusetts regulators now require utilities to consider alternatives before replacing pipes. Connecticut has decoupled gas revenues from sales and ordered a full review of its gas network to plan for electrification. These actions strategically prioritize maintaining reliability in the near term using natural gas while preparing for a future where gas infrastructure could be repurposed.

Southern and central states, including Pennsylvania, Virginia, South Carolina, and Georgia, continue to position natural gas as a key energy source for the future. Policies in these states emphasize infrastructure resilience and expansion to support industrial development and dispatchable power generation. Pennsylvania's Pipeline Investment Program funds new distribution lines to business parks, while Virginia's SAVE Act accelerates pipe replacement and modernization. South Carolina's Energy Security Act explicitly promotes new gas-fired generation to meet rising demand, and Georgia maintains programs to extend pipelines for economic development.

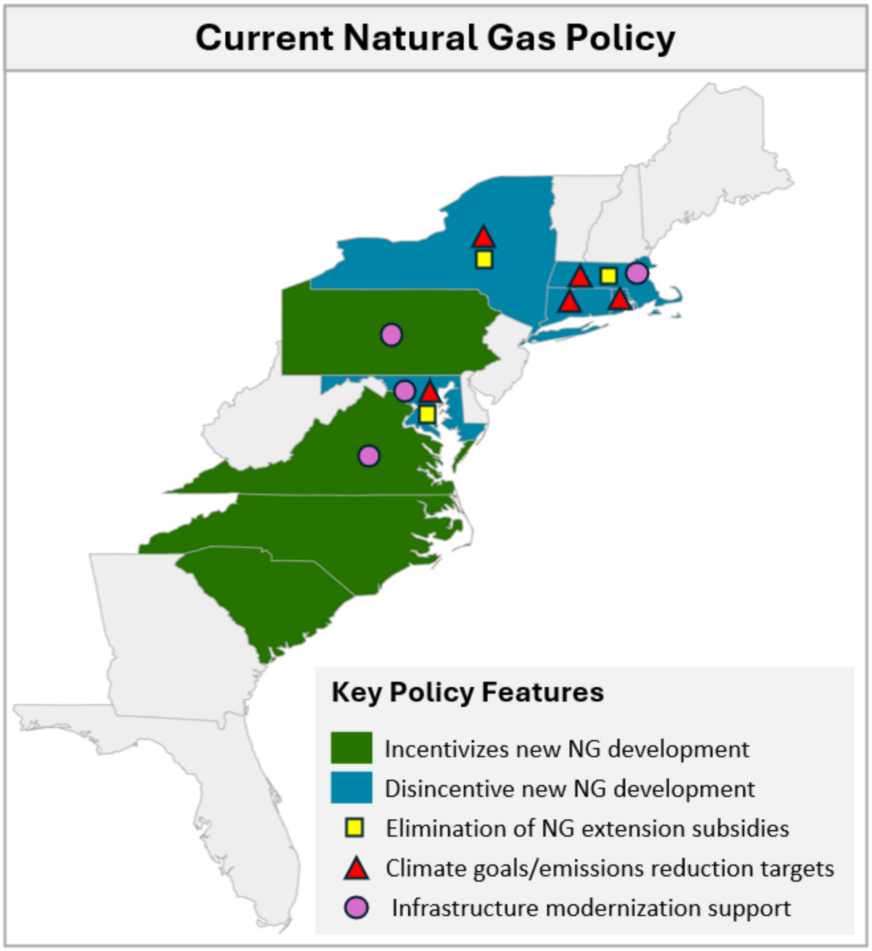


Figure 56. Current natural gas policy in the East Coast

Table 11. Natural gas policies in the East Coast

State	Policy/Program	Description
CT	Public Act 23-102 (2023)	Requires utilities to decouple revenue in a manner that does not remove the incentive to support the expansion of natural gas use.
	H.B. 5004 / Public Act 25-125 / "CT Clean Economy Act" (2025)	Directs PURA to open proceedings on the future of distribution system; calls for recommendations to align gas investments with emissions goals
MA	Title 22, Chapter 164, Section 145 (2024)	Requires utilities to file Gas System Enhancement Plans (GSEPs) for replacement or improvement of aging or leak-prone pipe.
	An Act Driving Clean Energy and Offshore Wind (2022)	Requires utilities to consider replacing gas infrastructure with utility-scale renewable thermal energy infrastructure
	DPU Order 20-80 / "Future of Gas Docket" (2023)	Requires utilities to consider non-gas alternatives to gas expansion projects and file Climate Compliance Plans every 5 years. DPU longer allows cost recovery for gas infrastructure without proof that non-gas alternatives were considered or for the promotion of natural gas expansion.
	DPU Order 20-80-E (2025)	Currently examining and revising the standards for investments to serve new customer
MD	Strategic Infrastructure Development and Enhancement (STRIDE) Law (2013)	Allows utilities to file plans for accelerated replacement of aging gas infrastructure and recover costs through a fixed surcharge
	HB 419 / Ratepayer Protection Act of 2025 (In progress)	Reforms STRIDE by requiring utilities to demonstrate cost-effectiveness, prioritize safety

		using modern leak detection, consider non-pipeline alternatives.
	PSC Order 91683 (2025)	Ended gas line-extension subsidies. Noted that free or discounted hookups conflicted with climate goals and risked stranded assets
NJ	Gas System Modernization Program (GSMP)	Initiative to replace at least 400 miles of aging infrastructure within PSE&G's pipeline network
NY	SB S8421 / Customer Savings and Reliability Act (In progress)	Repeals the "100-foot rule" that required existing ratepayers to subsidize gas hookups for new customers. Mandates utilities to develop gas transition plans for decarbonization.
	SB S4158 / NY Home Energy Affordable Transition Act (In progress)	Removes the legal basis and subsidies driving the expansion of gas systems and requires the commission to adopt rules to provide for the timely and strategic decarbonization and right-sizing of the gas distribution system in a just and affordable manner.
PA	Act 11 (2012)	Authorizes utilities to petition for a Distribution System Improvement Charge (DSIC) surcharge for recovering costs to repair, improve, or replace pipelines. Utilities must file a Long Term Infrastructure Improvement Plan (LTIIP) to qualify.
	Pipeline Investment Program (PIPE)	Grant initiative for expanding access to NG by providing funding for the construction of pipelines to serve industrial, business, and residential areas.
RI	Future of Gas Docket 22-01-NG (2022)	Investigates the future of the state's distribution system under the Act on Climate. Assesses how to align gas infrastructure with statewide climate goals.

	Clean Heat RI Program / American Rescue Plan Act (2022)	Provides rebates for heat pumps and heat-pump water heaters, encouraging households to switch from NG heating to electric alternatives.
NC	Chapter 6, Article 15, R6-96	Allows utilities to recover the "infeasible portion" of line extensions for large economic-development projects. Facilitates new gas infrastructure for industrial projects.
SC	Energy Security Act (2025)	Mandates expedited permitting for energy infrastructure projects, and encourages the development of nuclear resources, energy efficiency initiatives, and new generation facilities. Approves construction of additional NG power plant.
	Natural Gas Rate Stabilization Act (RSA) & SB 93 (In progress)	RSA (enacted 2005) stabilizes gas rates and aims to encourage gas infrastructure expansion. Bill 93 (2025) modifies RSA but retains the core policy of rate stabilization to support gas investments.
VA	Steps to Advance Virginia's Energy Plan (Save) Act (2010)	Allows utilities to file a Steps to Advance Virginia's Energy (SAVE) plan outlining eligible infrastructure replacement projects and a schedule for cost recovery via a SAVE rider surcharge.

Emerging Fuels Production and Transportation

Given that there are seventeen states within the East Coast region, there is considerable variation in how each state perceives the role and effectiveness of emerging fuels in its future energy mix. However, there were a few common themes that could be seen in most states, notably development of planning and advisory committees to identify opportunities and assess the efficacy of incorporating H_2, RNG, different forms of renewable energy, or carbon capture utilization and storage into their systems. For example, New Hampshire launched a Hydrogen Advisory Committee in 2023 for pure H_2 or blended natural gas uses (New Hampshire House 2025). Similarly, South Carolina established a nuclear advisory council under its Energy Security Act (SC General

Assembly 2025b), signed into law in May 2025, while New Jersey formed a H_2 fuel cell task force to help better inform consumers (NJ Department of Environmental Protection 2023). These initiatives signal a widespread, though measured, interest across the East Coast region in leveraging existing natural gas infrastructure for alternative uses.

RNG is the emerging fuel with the most incentives encouraging its adoption across the East Coast region. One example is Georgia, where multiple state agencies, including the Department of Agriculture, Forestry Commission, and Georgia Department of Transportation, streamline the approval process for biomass energy projects as part of their Environmental Permit and Grant Assistance program (GA Environmental Facilities Authority 2009). Public utility commissions in Maine (Maine Summit Natural Gas 2025) and Vermont (Vermont PUC 2022) have also supported the LDCs, Summit Natural Gas and Vermont Gas Systems, by allowing them to either have higher percentages of RNG included in their supply, or by allowing consumers to enroll in voluntary initiatives that support their RNG programs, respectively, Additionally, South Carolina has recently proposed a bill, S0556, that would establish a tax credit for equipment investments that help businesses collect, process, and inject RNG into transmission pipelines (SC General Assembly 2025a).

East Coast states have also shown growing support for H_2 deployment, often alongside their interest in RNG. The Florida Senate introduced a bill in 2023 that would have codified cost recovery mechanisms for RNG and H_2-based fuel injection (Florida Senate 2023). Pennsylvania’s Alternative Fuels Incentive Grant offers up to $500,000 per applicant for projects involving CNG, LNG, propane, H_2, and other alternative fuels, largely tailored to the transportation sector (PA Department of Environmental Protection 2025). Additionally, Virginia’s Energy Innovation Act and Sustainable Gas Program have allowed utilities to include RNG, certified natural gas, and H_2 into their fuel portfolios (VA Senate 2022). In New York, The Advanced Fuels & Thermal Energy Research Program supports the production, transmission, distribution, storage, and adoption of low-carbon fuels including clean hydrogen, especially for hard to electrify sectors. Virginia also has a Power Innovation Fund and Program that supports the research and development of innovative energy technologies, including but not limited to H_2, carbon capture and utilization, and energy storage (VA Department of Energy 2025).

In addition, the East Coast has proposed two H_2 hubs: the Appalachian Regional Clean Hydrogen Hub (ARCH2) and the Mid-Atlantic Clean Hydrogen Hub (MACH2). These hubs were initially awarded by DOE in June 2024, though their future remains uncertain as developers await clarity on federal grants and potential H_2-related tax incentives. Despite this uncertainty, both hubs outlined ambitious plans, including demonstration projects for clean H_2 production, transportation, and end-use applications across Ohio, Pennsylvania, West Virginia, Delaware, and New Jersey. If realized, these hubs would add hundreds of miles of new H_2 pipelines and expand infrastructure, helping to lower H_2 costs and accelerate emissions reductions.

The East Coast region also features a growing set of policies supporting carbon capture projects. Notably, West Virginia is the only state with Class VI primacy, which allows companies to seek approval directly from state agencies to utilize wells designated for geologic sequestration of carbon dioxide. In April 2025, their state senate also approved Bill 627, removing prohibitions on leasing state-owned pore spaces which will allow for an expansion of carbon sequestration projects (WV State Legislature 2025). Elsewhere, Pennsylvania's Act 87 was signed into law in July 2024, establishing a regulatory framework for CCUS projects and clarifying permitting processes for operators (PA General Assembly 2024) . Meanwhile, Maryland is currently reviewing their House Bill 0155, which would establish a carbon capture opportunity program to support related projects and research (MD General Assembly 2024).

Many incentives and programs aim to advance renewable energy, often aligned with state efforts to meet energy generation targets and net-zero commitments. In many of these states (e.g., Connecticut, Rhode Island, Vermont), future energy plans require phasing out fossil fuels to meet ambitious net-zero goals. One such initiative is Maryland's Renewable Energy Portfolio Standard Program that requires 52.5% of the state's energy be derived from renewable sources by 2030 (MD Department of Legislative Services 2025). Emerging fuels, such as H_2 and RNG, can complement these efforts by providing low-carbon options for sectors that are harder to electrify, supporting reliability while accelerating progress toward net-zero.

Table 12. Policies and programs relevant to emerging fuels and renewable energy adoption

State	Policy/Program Name	Description

CT	House Bill 5004 (2025)	Act setting forth GHG emission reduction and zero-carbon electricity production targets
DE	Delaware Climate Change Solutions Act (2023)	Establishes a target of GHG emission reduction over the medium and long term
GA	Environmental Permit and Grant Assistance Program (2024)	Program helping to accelerate bioenergy project development
MA	Department of Public Utilities Order 20-80 (2023)	Order mandating that non-gas alternatives must be considered to allow cost recovery for gas infrastructure
MD	Renewable Energy Portfolio Standard Program (2025)	Standard requiring energy to be derived from renewable sources, including “qualifying biomass”
	House Bill 0155 (2025)	Bill establishing the Carbon Capture Opportunity Program to assist CCUS research
NC	NC Farm Act/Senate Bill 605 (2021)	Allows a single general permit for companies, thus fast-tracking biogas projects
NH	Hydrogen Advisory Committee/HB 139 (2023)	Committee to more deeply consider H_2 integration opportunities
NJ	Bill A577 (2023)	Bill aiming to create a program allowing utilities to procure RNG and build related infrastructure
NY	Senate Bill S07134 (2025)	Bill advocating for the establishment of carbon capture projects to achieve GHG reduction goals
	Senate Bill S7132A (in progress)	Bill would require the establishment of a renewable hydrogen incentive program

	The Advanced Fuels & Thermal Energy Research Program	Program supporting research and innovations for clean hydrogen production, infrastructure, and low-carbon fuels application
PA	Act 87 (2024)	Act establishing a legal framework for CCUS, streamlining permitting, and enabling workforce opportunities
	Alternative Fuels Incentives Grant Program (2025)	Program offering up to $500,000 per year to projects involving LNG, CNG, H_2, and other alternative fuels
SC	Energy Security Act (2025)	Far-reaching act encouraging the buildout of new generating resources to stimulate economic growth
	Bill S0556 (2025)	Proposed bill establishing a tax credit for RNG production in South Carolina
VA	Power Innovation Fund and Program (2025)	Grants made available to the research and development of innovative energy technologies
	Clean Energy Innovation Bank (2024)	Fund serving as a hub to help accelerate the deployment of clean power generation and energy infrastructure
VT	5085-PET (2022)	Petition from state utility, VGS, to include up to 6% RNG in their system
WV	Bill 627 (2025)	Bill allowing the state to lease underground pore spaces beneath state parks and forests for carbon sequestration

Energy System Reliability & Workforce Development

Enhancing natural gas system reliability and cultivating a skilled energy workforce are shared priorities across states in the East Coast. Nearly every state in the region has implemented measures to modernize aging gas pipelines and enhance grid resilience against severe weather, though reliability efforts vary from state to state. Delaware for example launched a Grid Resiliency Grant to storm-harden utilities while New Jersey created an Energy Resilience Bank to fund substation flood protection and backup generation after Hurricane Sandy. Connecticut's response to storms was to harden infrastructure and diversify energy sources through Public Act 12-148, which set emergency performance standards for gas utilities and launched grants for microgrids and generator projects that keep critical facilities powered during outages.

Workforce development is another pillar of East Coast energy policy, with states tailoring programs to their energy system strategies. States recognize the need to upskill workers for new technologies and replace retiring utility crews, but the emphasis ranges from facilitating a just transition in decarbonizing states to bolstering trades training where gas development continues.

In the Northeast, workforce initiatives are closely tied to clean energy and gas transition policies. New York's 2019 Climate Leadership and Community Protection Act (CLCPA) not only set emissions targets but established a Just Transition Working Group to support fossil fuel workers moving into green jobs. The state has committed over $120 million through NYSERDA and the Department of Labor to train 40,000+ workers by 2025 in areas such as energy efficiency, heat pumps, and grid modernization. Connecticut's 2023 Green Economy Act created a statewide Clean Economy Council to re-train natural gas utility workers for roles in geothermal heating, solar installation, and HVAC electrification. Massachusetts regulators, through DPU Order 20-80, urged gas utilities to collaborate with labor unions and the Massachusetts Clean Energy Center on reskilling programs, emphasizing opportunities for historically underrepresented groups. These states often pair workforce development with climate action, focusing on skills for heat pump installation, H_2 safety, and electrification.

By contrast, states expanding gas utilization emphasize vocational training and apprenticeships to meet immediate industry needs. Georgia's 2023 partnership between Atlanta Gas Light and technical colleges launched a Natural Gas Technician Certificate program—a fast-track curriculum producing job-ready pipeline mechanics skilled in installation, leak repair, and safety. New Jersey and North Carolina also operate apprenticeship and pre-apprenticeship programs for energy jobs. New Jersey's Clean

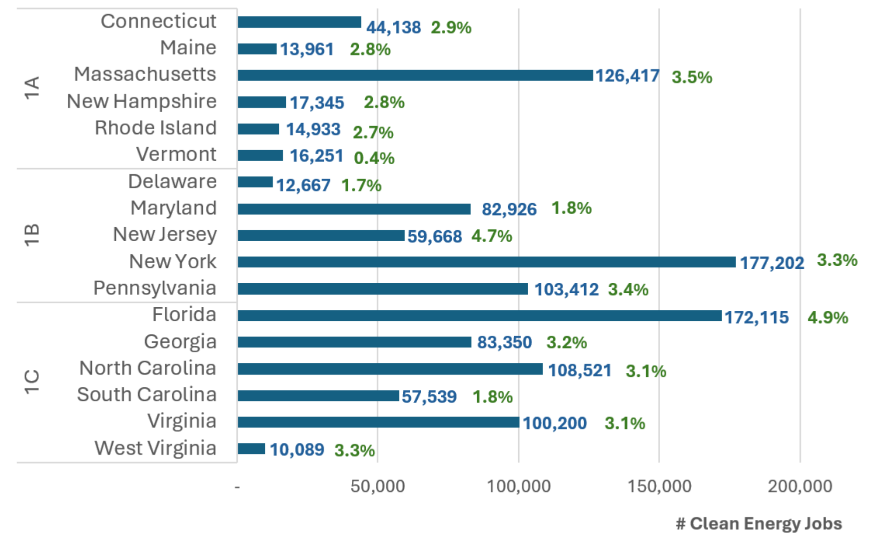
Energy Academy and Green Workforce Training Initiative fund union apprenticeships for utility and renewable projects, while North Carolina's universities and community colleges train workers for solar, battery, and efficiency roles alongside traditional linework. In Appalachia, where coal and gas employment has been central, West Virginia and Pennsylvania leverage the Appalachian Regional Commission's POWER Initiative to retrain displaced coal miners and gas workers for emerging energy sectors.

Across the East Coast, states enable clean energy job growth by investing in training infrastructure, supporting workers in legacy fuel industries, and building capacity for clean energy systems (**Figure 61**). Massachusetts funds technical and vocational institutions through the Skills Capital Grant Program, while North Carolina, New Jersey, and South Carolina operate state and university initiatives connecting workers to clean energy careers. New York maintains a broad portfolio through NYSERDA programs and the Clean Energy Workforce Initiative, preparing workers for electrification, offshore wind, solar, and advanced manufacturing. These efforts aim to expand training, introduce stackable credentials, and modernize skills for evolving utility functions.

Several states also address specialized skill gaps tied to emerging fuel systems. North Carolina identifies needs in carbon management, H_2 technologies, and large-scale utility construction. Virginia's methane capture grants strengthen technical expertise in methane recovery and environmental engineering. West Virginia's proposed ARCH2 H_2 hub would expand training for H_2 production and related activities. New York is piloting cross-training programs enabling gas utility workers to transition into electrification and geothermal roles. Collectively, these initiatives reflect a shared commitment to preserving existing expertise while minimizing workforce disruption and preparing for a resilient energy future.

Clean Energy Jobs & Growth Rate (2022 – 2023)

DOE 2024 U.S. Energy & Employment Jobs Report



In the U.S. Job Market…

- **Vermont** has the highest proportion of clean energy jobs (5.2%), followed by **Massachusetts** (3.4%), with **Maryland** coming in 5th (3.0%)
- **Florida** has the 3rd most renewable electric power generation jobs (29,146) and the 4th greatest number of clean energy jobs (172,115)
- **New York** has the 3rd greatest number of clean energy jobs (177,202) and the 4th most renewable electric power generation jobs (27,384)

Figure 57. Clean energy job growth in East Coast states (data from the DOE 2024 U.S. Energy & Employment Jobs Report)

Table 13. Workforce development policies and programs

State	Policy/Program	Description
CT	Green Economy Act (HB 5004, 2025)	Establishes Clean Economy Council; expands training for clean energy jobs
DE	Clean Energy & Climate Jobs Workforce Assessment (2024)	Identifies workforce gaps and training needs
	Delaware Energy Act Amendments (SB 7 of 2023)	Adds energy workforce development to State Energy Office mission
GA	Natural Gas Technician Training Program (2023)	Certificate program for pipeline mechanics
	Georgia Quick Start	Customized training for clean energy manufacturing
MA	Massachusetts Skills Capital Grant Program	Supports vocational training facilities

	DPU Workforce Transition Directive (2020)	Encourages just transition training for gas workers
MD	Just Transition Employment & Retraining Working Group (2019)	Workforce planning for clean energy transition
	ARC POWER Initiative	Funds job training in coal-impacted regions
NC	Workforce Training Initiatives (2023)	Apprenticeships and clean energy programs
NJ	Apprenticeship Network & Green Workforce Grants	Expands training for energy jobs
NY	Clean Energy Workforce Initiative (2022)	Training programs for clean energy jobs
	Northeast Regional Hydrogen Hub (2023)	Workforce training for H_2 projects
PA	Energy Infrastructure & Jobs Tax Credits (Act 108 of 2022)	Incentivizes H_2 and gas projects with job requirements
SC	Clean Energy Workforce Development Tool (2021)	Connects individuals with training programs
	City of Columbia Grid Resilience Workforce Grant (2023)	Trains workers in resilience technologies
VA	Methane Capture Grants (2025)	Technical skill development in methane recovery and environmental engineering
VT	Climate Workforce Coalition (2021)	Prepares workforce for climate-friendly jobs
WV	ARC POWER Programs	Retrains coal economy workers for energy jobs

	ARCH2 Hydrogen Hub	Training programs for H_2 production and related systems

The One Big Beautiful Bill Act

The One Big Beautiful Bill Act (OBBBA), signed into law on July 4, 2025, has introduced uncertainty into state-level energy system plans and strategies through the removal of tax credits for wind, solar, and battery storage, especially in states previously utilizing federal incentives from the Inflation Reduction Act. In an analysis published November of this year, Evolved used their Ensemble modeling framework to examine the potential impacts of this policy shift on the county's power systems through 2040 (Evolved Energy Res. 2025). The results show wind and solar growth slowing dramatically as a result of the OBBBA, with median U.S. additions falling from 985 GW under IRA to 700 GW and offshore wind nearly halting. This has the potential to create a critical gap in energy and power supply for states utilizing significant offshore wind, including New York, New Jersey, and Massachusetts, which would need to be filled by developing additional capacity.

Nuclear deployment occurs consistently in thirteen states across the modeling scenarios, including Florida, Maryland, New York, North Carolina, Pennsylvania, South Carolina, Virginia, and Wyoming. New York showed the greatest potential for nuclear deployment, developing up to 7 GW of new nuclear capacity by 2040 and more than doubling advanced geothermal deployment under the OBBBA compared to IRA projections. These changes would require major infrastructure investments and regulatory agility, as well as accelerated workforce training for nuclear technologies. The potential for natural gas expansion to meet high growth in data center load was also examined in this analysis. The model found Virginia to be among the states most likely to construct large amounts of new gas capacity.

Discussion

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

Existing Infrastructure Utilization

Repurposing existing infrastructure offers a cost-effective and practical strategy to accelerate the deployment of emerging fuels such as H_2, RNG, and SNG. Leveraging the East Coast's extensive pipeline network and existing rights-of-way can significantly reduce capital costs, minimize construction-related emissions, and shorten permitting timelines compared to new builds. Similarly, RNG can be injected into existing systems without technical blending limits once upgraded to pipeline quality, avoiding major infrastructure overhauls. Pipeline systems with underutilized capacity provide immediate scalability for both fuels. Repurposing also mitigates regulatory delays, as projects using existing corridors often face fewer environmental reviews.

While repurposing offers compelling benefits for decarbonization, success will depend on detailed engineering evaluations, regulatory clarity, and supportive policies to ensure safe, reliable, and economically viable integration of H_2, RNG, and SNG into existing infrastructure.

Technical Considerations

Since RNG and SNG are chemically similar to conventional natural gas, no significant modifications and assessments are needed for integration with existing infrastructure. However, operators must ensure these fuels meet pipeline gas quality specifications prior to injection. Trace constituents (e.g., siloxanes, VOCs) can damage pipelines and end-use equipment. Gas conditioning and continuous composition monitoring are essential quality assurance measures to protect system integrity and reliability.

In contrast, H_2 integration requires more extensive considerations. Material compatibility is critical: modern polyethylene distribution mains and lower-strength carbon steels are generally suitable for H_2 blends, but existing pipeline condition matters since H_2 can accelerate pre-existing defects. Comprehensive integrity assessments are necessary before conversion.

H_2's physical properties also introduce operational challenges. Its lower density will require approximately three times more compression power compared to natural gas and will require compressor upgrades or replacements. Depending on the blend percentage, upgrades or replacements may still be needed. Operators should inventory compression assets and collaborate with manufacturers to identify necessary modifications. Additionally, H_2's volumetric energy content is about one-third that of natural gas. As a result, a H_2 blend will have a lower higher heating value compared to conventional natural gas. A greater volume of gas is needed to continue delivering the same amount of energy to end-users. This has implications for system capacity, particularly in regions where pipelines already operate near capacity and will require system planning to identify constraints and upgrade needs.

Finally, end-user requirements must be considered. Certain industrial sectors (e.g., chemicals, metals, glass) have strict gas quality specifications and may not accept H_2 blends. Mitigation strategies could include installing H_2 separation technologies at delivery points or providing alternative supplies such as RNG or SNG. Early engagement with these customers is essential to align infrastructure planning with industrial needs. Another important consideration is the emissions reduction impact potential of H_2 by end-use application. For instance, blending 20% H_2 into natural gas can reduce CO_2 emissions by approximately 7%. However, the emissions reduction of using H2 varies across sectors. According to a 2024 Switchbox report, decarbonizing buildings, such as residential and commercial appliances, may be more efficiently achieved through electrification rather than H2 blending (Switchbox and EDF 2024). In contrast, hard-to-electrify applications, such as heavy industry and power generation, are better suited for H_2-based solutions.

Economic Considerations

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 must account for expenses related to fitness-for-service assessments, enhanced gas quality monitoring, and upgrades or replacements of compressors, valves, and other critical components. These factors are essential for ensuring safe and reliable H_2 transport.

Operational considerations also play a major role. Because H_2 has approximately one-third the volumetric energy content of natural gas, blends will require greater gas volumes to deliver equivalent energy to end-users. This shift increases procurement and compression requirements, which can drive up operating costs. System planning must address these logistics, particularly in regions where pipelines already operate near capacity.

Maintenance costs will also rise as integrity management programs adapt to H_2's unique properties. H_2 pipelines may require more frequent inspections and leak surveys. Inspection frequency will depend on factors such as operating pressure, wall thickness, tensile strength, and pipeline age. For RNG and SNG, while existing infrastructure is generally compatible, robust gas quality monitoring at interconnection points remains critical to prevent damage from trace constituents.

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. Operators should evaluate financial implications and explore strategies to offset costs, such as long-term procurement contracts, regulatory incentives, subsidies, and low-carbon fuel standard credits. These measures will be essential to support the transition while maintaining affordability and reliability.

Potential Impact of Assumptions on Results

LCA

The hybrid LCA modeling approach captures the influence of energy sources, but it misses the opportunity for additional granularity that could be achieved by developing independent OpenLCA models for each scenario. This additional modeling complexity would allow upstream inventories to reflect differences in capture technologies, retrofit configurations, and process efficiencies, thus improving sensitivity and providing a more detailed understanding of how system-level design (state or project specific) choices affect lifecycle performance.

The model uses a cited standard for methane leakage rate (0.56%) from the NETL baseline methane bottom-up and regional averages for natural gas supply, which could be an underestimate ion of leakage in the East Coast due to its older infrastructure, especially in urban distribution systems.

Carbon capture rates and retrofit feasibility are modeled under ideal conditions, real projects may face site-specific constraints such as limited storage availability, higher energy consumption, and longer transport distances. RNG pathways assume simplified feedstock sourcing and conversion efficiencies, whereas actual supply chains may involve longer transport distances or mixed feedstocks. These aforementioned changes could result in higher CI values.

Electricity assumptions rely on weighted averages of balancing authority generation profiles; however, projects may address power needs through installations or contracts that more easily reduce CI, like on-site production (behind the meter), power purchasing agreements (PPAs), or renewable energy certificates (RECs). Additionally, likelihood of other system efficiency improvements have not modeled, but these could significantly lower carbon intensity compared to modeled grid averages.

The analysis implicitly assumes a one-to-one displacement of NG with SNG/RNG (on a kg basis) without altering any other boundary conditions. In LCA methodology, substituting fossil natural gas with SNG triggers system wide changes along the entire supply chain that may not be captured when all other parameters are held constant.

Learning Rates

In the OL-NEMS Hydrogen Market Module (HMM), learning is modeled as an endogenous process and is technology-specific. For each doubling of installed capacity, capital costs decline by 3%, making cost reductions scenario-dependent. These learning rates may be optimistic for mature technologies such as SMR, while potentially conservative for electrolyzers, which have historically shown faster cost declines.However, even if learning rates are adjusted upward for all technologies, the model does not include a global “minimum learning rate”, such that costs only decrease when new capacity is built in the U.S. This creates a structural limitation: electrolyzers, being more expensive than SMRs initially, are unlikely to see significant deployment under most scenarios, even with higher learning rates. Consequently, their cost reductions remain minimal because capacity additions are limited. Some indirect benefits for electrolyzers will likely come from declining costs of renewable power technologies, which reduce delivered electricity prices. These reductions are captured in the HMM through renewable technology price inputs, not through embedded electrolyzer cost assumptions. The National Renewable Energy Laboratory’s Annual Technology Baseline (ATB) 2024 data are incorporated for renewable technologies, but their influence on electrolyzer economics is indirect and limited to electricity price impacts. Future studies could explore sensitivity analyses by adjusting learning rates across all H_2 technologies and evaluating the resulting cost trajectories.

Blending Rates

This study 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.

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 utilized a number of assumptions, including the NETL calculation (**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).

Required Incentives 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., CIRenew = 0). Since the LCA has the upstream CO_2 emissions data available, the "lifecycle" 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. Additionally, the calculated incentives apply to 2025 and may vary in the future if production costs decline.

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.

In addition, the NEMS model indicates that the most promising pathway is RNG produced through gasification of industrial wastewater, requiring an estimated incentive of approximately \$93/ton of CO_2. This makes it a pathway likely to compete with conventional end-use carbon capture, which typically costs \$40-\$120/ton of CO_2. However, this scenario was not included in the TEA or LCA analyses due to insufficient resource availability data. As a result, no additional details are available, though this pathway could be viable in certain states.

Other Potential Enhancements and Refinements

The following considerations represent potential enhancements and refinements to the current study. While these elements fall outside the present scope, they highlight factors that could influence technical, economic, and environmental outcomes if incorporated in future analyses.

- Introducing low/base/high feedstock cases and dynamic decay curves would significantly affect OPEX and CAPEX estimates, altering plant capacity assumptions and economies of scale. Policy-driven feedstock shifts (e.g., organics bans, PFAS regulations) could increase costs and complexity, potentially making some projects less viable.

- Accounting for feedstock concentration relative to pipeline proximity and seasonal variability would highlight regional cost disparities. Modeling import dependency and technology competition introduces market risk factors. States reliant on imported waste (e.g., NY) could face higher feedstock costs, while emerging fuels (e.g., H_2) may reduce RNG competitiveness, increasing stranded asset risk.
- Using probabilistic cost modeling (Monte Carlo simulations, learning curves) would replace single-point estimates with risk-adjusted forecasts, improving credibility but potentially widening uncertainty ranges. Equipment lifespan and modular flexibility considerations could alter financial viability and investment strategies.
- Sensitivity analysis and portfolio optimization would identify key cost or emission drivers and optimal fuel mixes, improving strategic planning. The H_2 fuel pathways do not consider the integration of battery energy storage systems, which could influence levelized cost estimates by altering system flexibility, operational efficiency, and overall economics.

Key Challenges and Opportunities

Workforce Development

Workforce development is a critical factor in advancing emerging fuels adoption and meeting rising energy demand, as the supply of skilled labor has not kept pace with the sector's changing needs. Across the East Coast, industry, academic institutions, and state agencies are coordinating to align training programs with anticipated skill requirements. As discussed in the **East Coast Landscape** section, several states have also introduced policies that support workers in existing fuel industries while building the workforce capacity needed to support emerging fuels integration.

Collectively, these efforts indicate a regional approach that enhances training capacity, supports workers connected to conventional fuel industries, and develops the specialized skillsets required for emerging fuels integration and broader improvements in energy resilience. To build on this momentum, states could explore the following opportunities:

- Regional Credentialing System: Shared credentialing platform would allow workers to move seamlessly between states, supporting mobility and reducing workforce shortages.
- Public-Private Partnerships: Collaboration among state programs, energy companies, and technology providers to co-develop training aligned with real-world projects (e.g., offshore wind farms, H_2 hubs).
- Innovation in Curriculum: Integration of emerging topics like carbon capture and H_2 safety, into vocational programs.
- Data-Driven Workforce Planning: Use of labor market analytics to anticipate skill gaps and adjust training investments dynamically.

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 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 emerging 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.

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. Ensuring financial support for weatherization and infrastructure hardening are available through grants or banks can encourage operators to make preemptive investments to modernize their systems while lowering the regulatory hurdle of applying for a separate base rate increase or cost-recovery mechanism.

Finally, aligning regulatory frameworks, funding/financing mechanisms, and stakeholder collaboration across East Coast states will be vital to scaling resilient and reliable gas infrastructure. Establishing state-level safety standards for H_2 would help encourage H_2 utilization. Developing harmonized regulatory frameworks for H_2 across the region could reduce investor uncertainty, simplify state permitting requirements, and facilitate cross-state H_2 pipeline projects. Harmonizing training for permitting staff and ensuring public engagement will help overcome community concerns about H_2 blending, new pipelines, or CO_2 sequestration and accelerate project approval timelines.

Other Investments to Support Adoption of Emerging Fuels

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 and RNG. 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

Accelerating the adoption of emerging fuels in the East Coast will require a coordinated portfolio of supportive programs that address technical, economic, and workforce challenges identified in this case study. These programs should be designed to complement existing state and federal initiatives while filling critical gaps in infrastructure readiness, cost competitiveness, and market development.

Potential opportunities include:

- Scale-Up of RNG and LFG Technologies: Invest in research and demonstration projects for high-throughput biodigesters, advanced LFG upgrading, and co-digestion systems at wastewater treatment plants. These technologies can significantly reduce production costs and improve RNG availability in urban and rural areas.
- H_2 Infrastructure Pilots: Fund pilot projects for H_2 blending in existing pipeline systems. These pilots should prioritize regions with modernized pipeline materials and high industrial demand to validate technical feasibility and safety.
- Regional Low-Carbon Fuel Standard (LCFS): Establish an East Coast LCFS that includes RNG and H_2 pathways, creating a consistent market signal for low-carbon fuels. Pair this with carbon-intensity benchmarks to incentivize the most sustainable production methods.
- Targeted Incentives and Tax Credits: Expand or adapt existing credits (e.g., 45Q, 45V) to reflect regional cost structures and feedstock availability. State-level programs could offer stackable incentives for projects that integrate multiple decarbonization strategies (e.g., RNG + CCS).
- Utility Procurement Programs: Encourage utilities to adopt RNG and H_2 procurement targets, supported by cost-recovery mechanisms and tariff revisions. These programs can create predictable demand and reduce investor risk.
- East Coast Emerging Fuels Consortium: Establish a multi-state consortium to harmonize safety standards, permitting processes, and gas quality specifications for RNG and H_2 blends. This collaboration can reduce regulatory uncertainty and streamline project timelines.

Conclusion

The East Coast region presents a unique and complex landscape for integrating emerging fuels into existing natural gas infrastructure. This case study demonstrates that leveraging H_2 and RNG can reduce GHG emissions while supporting energy reliability and resilience. However, the feasibility of these pathways depends on multiple factors, including resource availability, infrastructure readiness, regulatory clarity, and cost competitiveness.

Key findings indicate that:

- Infrastructure repurposing offers a cost-effective strategy for scaling emerging fuels, particularly RNG, which is chemically similar to natural gas. H_2 integration requires more extensive assessments and upgrades due to material compatibility and operational constraints. The SNG pathways assessed do not provide emissions reduction benefits.
- Resource distribution varies widely across states, necessitating a tailored approach to fuel production and blending strategies. States with abundant biomass and LFG are well-positioned for RNG development, while states with strong renewable electricity potential and natural gas reserves can support low-carbon H_2 production. Strategic siting of production facilities near feedstock sources and end-use markets will be critical to minimize costs and optimize logistics.
- Economic viability remains a challenge, as the emerging fuel pathways currently exceed the cost of conventional natural gas. Incentives, such as tax credits and low-carbon fuel standards, will be critical to bridge this gap and accelerate adoption.
- Policy alignment is essential to enable cross-state projects, harmonize safety standards, and reduce permitting timelines. Coordinated frameworks for H_2 blending, CO_2 transport, and RNG integration will help mitigate uncertainty and attract investment.
- Workforce development and infrastructure modernization must advance in parallel with technology deployment. Scaling emerging fuels will require a skilled workforce capable of supporting new technologies and maintaining system integrity. Investments in training programs, credentialing systems, and modernization of aging pipeline networks will ensure safe operations and long-term resilience.

In summary, the East Coast has the potential and resource diversity to become a leader in low-carbon fuels adoption. Achieving this vision will require a strategic mix of infrastructure upgrades, supportive policies, targeted incentives, and collaborative planning across states. By leveraging existing assets, aligning investments with regional strengths, and fostering innovation in both technology and workforce development, stakeholders can accelerate the transition toward a cleaner, more resilient, and economically competitive energy future.

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