GTI ENERGY

RAISE

Reliable Affordable Infrastructure for Secure Energy

October 2026

Regional Emerging Fuel Pathways for a Reliable and Resilient U.S. Energy Future

APPENDICES



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Appendix A: Emerging Fuel Pathways Considered

Hydrogen

Current hydrogen (H_2) markets are dominated by steam methane reforming (SMR) of natural gas, achieved at approximately $1/kg (Lewis et al., 2022). As a carbon-free energy carrier, H_2 can help decarbonize heavy industries, long-distance transport, and energy storage. However, for a low-carbon future, its production must minimize carbon emissions. In this case study, H_2 production via SMR of natural gas incorporating carbon capture and storage (CCS) is considered, with an overall capture rate of at least 96% (Lewis et al., 2022). This pathway is similar to conventional H_2 production but with the addition of solvent-based CO_2 capture systems for capturing from both the syngas and the flue gas streams and with a CO_2 compression train.

Along with SMR, hydrogen production with autothermal reforming of natural gas is considered. Autothermal reforming (ATR) of natural gas with CO_2 capture from syngas at an overall capture rate of at least 94%, as defined by the chosen literature source (Lewis et al., 2022). Note that the capture rates presented are a function of the selected process design and nominal capture rates of individual CO_2 capture units, which were obtained from CO_2 capture technology developers. The Lewis, et al., (2022) SMR case utilizes both CO_2 capture from syngas at 95% and flue gas at 90%, resulting in high overall capture rates for SMR, as a goal of the study was to evaluate configurations with high capture rates. If CO_2 is only captured from syngas, for example, the SMR capture rate would be about 62% (Lewis, et al., 2022). The ATR design only includes CO_2 capture from syngas at a nominal rate of 95 percent, as the flue gas stream is relatively small and contains a small concentration of CO_2, so additional capture is not economic. However, if the syngas capture unit rate is increased from 95% to 99%, overall ATR capture rates would increase to 98%. Lummus Technology describes various SMR and ATR configurations and their CO_2 removal rates, which aligns with the configurations and capture rates seen in Lewis, et al. (2022) (Lummus Technology, 2024). Costs are reflective of the selected process designs from Lewis, et al., (2022).

H_2 production via plasma pyrolysis of natural gas involves the utilization of a plasma torch to decompose methane (CH4) into gaseous H_2 and solid carbon, which avoids significant direct CO_2 emissions. A benefit of this technology is the production of solid carbon, which can be sold to provide revenue to the plant and reduce the cost of H_2 .

Hydrogen production cases with electrolysis are limited to proton exchange membrane (PEM) electrolysis technology in which electricity is used to split water to form hydrogen and oxygen byproducts, avoiding any direct CO_2 emissions. Since this pathway uses a significant amount of electricity, it is important that the electricity is sourced from low-carbon resources. H_2 via Electrolysis cases are expanded to five sub-cases to evaluate production using six different low-carbon electricity sources: photovoltaic (PV) solar; onshore wind; nuclear power; hydropower; biomass without CCS.

Renewable Natural Gas

The RNG cases involve the biological conversion of organic waste resources into a methane- rich gaseous drop in-fuel for natural gas. A benefit of RNG over low-carbon H_2 is that it can be directly substituted for natural gas without any retrofitting or replacement of end-use technologies.

Three RNG fuel production pathways are considered: upgrading of landfill gas, anaerobic digestion of dairy manure, and anaerobic digestion of wastewater.

Upgrading landfill gas involves the collection of municipal solid waste landfill gas via a gas collection system and refinement of the landfill gas to pipeline specifications.

Anaerobic digestion of dairy manure and wastewater is achieved via anaerobic digesters onsite to the feedstock source, which requires some thermal inputs to satisfy methanogenesis process requirements.

Appendix B: Energy Systems Modeling

OL-NEMS Assumptions

General Assumptions

- Data center demand forecasting: the OnLocation Medium Growth projection is used to assess the impacts of anticipated growth in data center electricity demand (Figure 1). This projection estimates national data center electricity consumption by fitting an S-curve to the midpoint of Lawrence Berkeley National Laboratory's (LBNL) high- and low-growth projections for the 2022-2028 period and extrapolating beyond that timeframe to capture longer-term growth trends. This approach provides a balanced forecast of future data center electricity demand while accounting for the rapid expansion of data center infrastructure (Lawrence Berkeley National Laboratory, 2024).

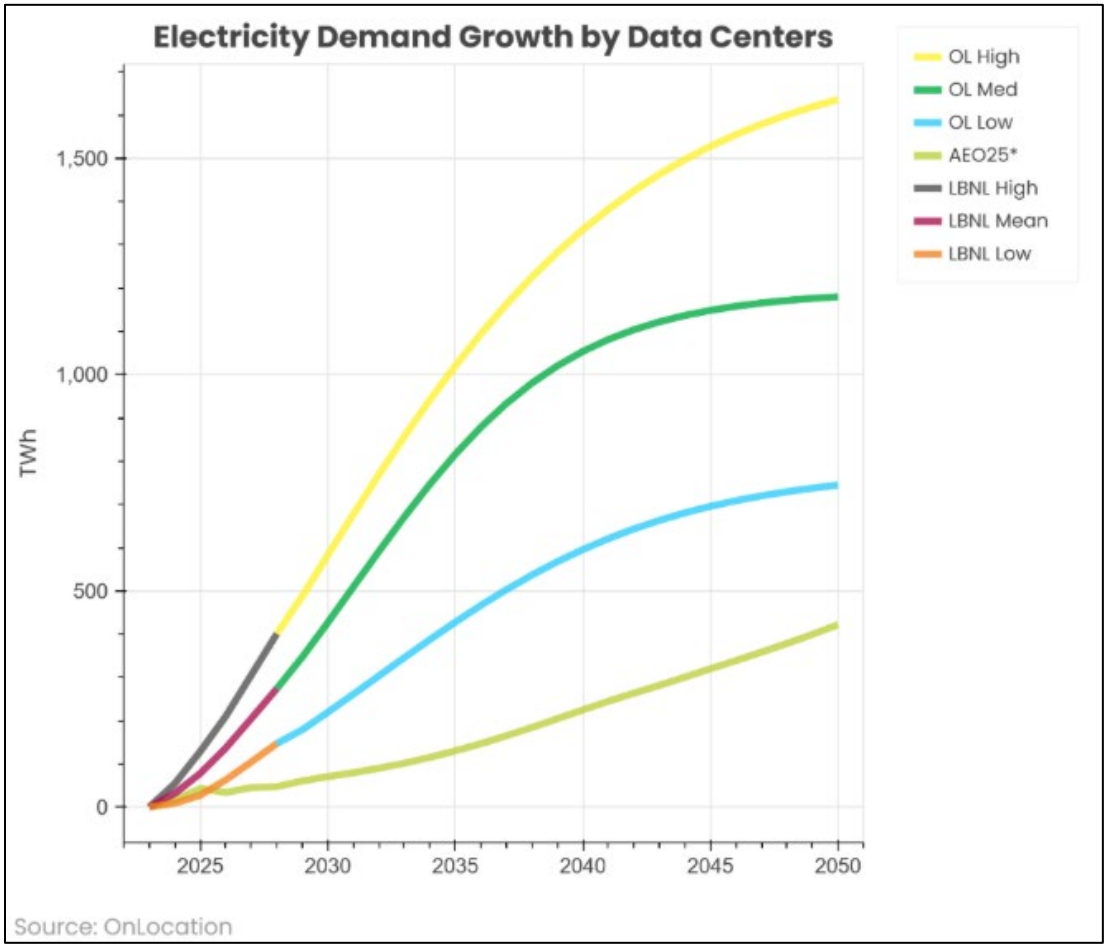


Figure 1. Electricity Demand Growth by Data Centers (Source: OnLocation)

- LNG planned capacity: LNG planned capacity was updated using data from EIA's AEO 2026, which reflects the latest capacity under construction or approved for construction. Figure 2 shows the updated planned LNG terminal capacity through 2029 on an annual basis (EIA, 2026).

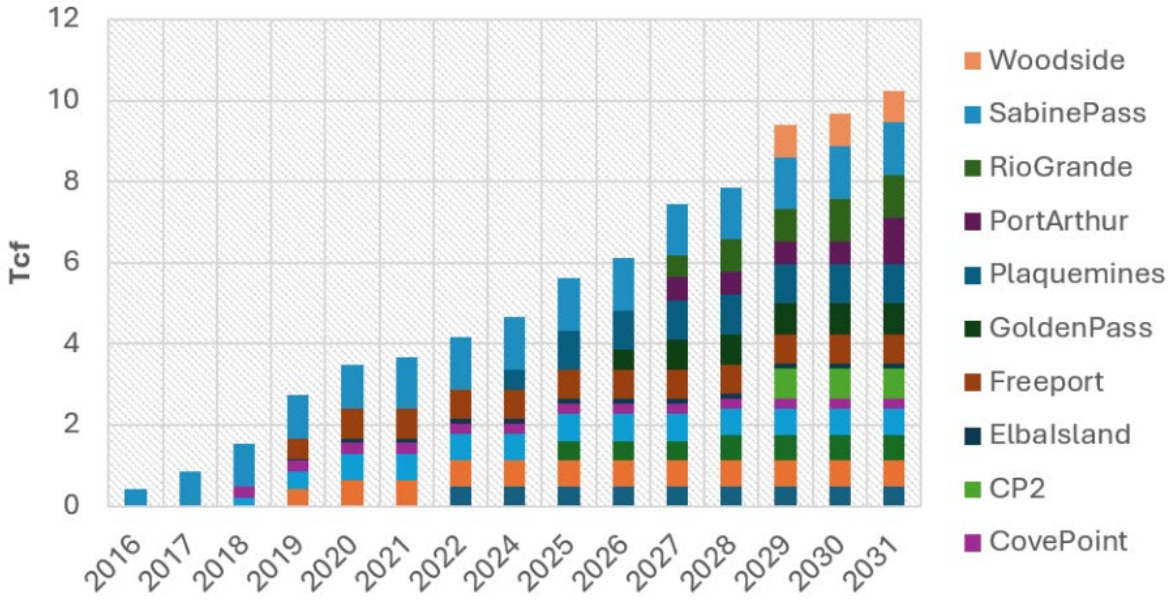


Figure 2. LNG Planned Capacity Growth

OL NEMS: Low-Carbon H_2

The Low-Carbon H_2 case has the same assumptions as the BAU AEO25 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.
- Blending begins in 2031 and reaches the maximum in 2050.
- 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 Low-Carbon H_2 are based on the TEA results.

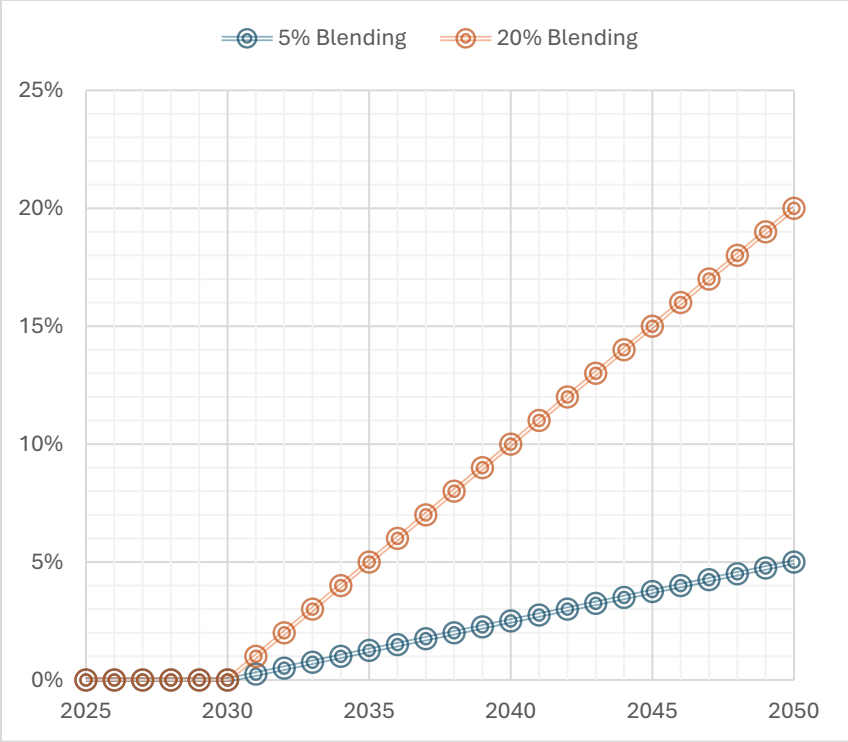


Figure 3. Hydrogen Blending % by Year

OL-NEMS: RNG

The RNG case has the same assumptions as the BAU AEO25 Reference case in all aspects except the following:

- RNG feedstock and levelized costs were added by state for the following types: Landfill Gas, Wastewater Recovery, and Animal Manure.
- Note that starting in AEO25, EIA projects the production of RNG based on new landfill and dairy farm RNG projects (EIA, 2025). Potential landfill RNG projects are populated using the Landfill Methane Outreach Program (LMOP) database (EPA, 2026). To estimate the RNG capacity of dairy farms, data on dairy farm capacity by state from the USDA Census of Agriculture was used (U.S. Department of Agriculture, 2022). RNG production costs are based on a study from the American Gas Foundation (ICF, 2019).
- RNG is assumed to be blended into natural gas pipelines.
- In blending cases, the BAU Reference case natural gas demand and available feedstocks from TEA results were used to determine the maximum RNG blending possible in each region. Table 1 shows the low and high blending levels allowed within each region used to run the RNG blending based on the Reference case. In

each case, the blending starts in 2031 and ramps uniformly to the stated levels by 2050.

Table 1. RNG Blending Low and High Blend %

Region	Low Blend %	High Blend %
East Coast	1.0	4.0
Midwest	1.0	4.0
Gulf Coast	0.5	1.5
Rocky Mountain	1.0	3.0
West Coast	3.0	7.5

Hydrogen Market Module Description

The Hydrogen Market Module (HMM) is a key supply module included in OL-NEMS to represent H_2 as a feedstock and energy carrier. HMM enables understanding of the development of H_2 under different technology, policy, and market scenarios.

Technology Updates for H_2

For the low-carbon H_2 production technologies considered in this case study, OL-NEMS includes updated technology costs. For production technologies not currently represented (e.g., NG SMR without CCS), existing data was added to provide a full suite of options for the BAU scenarios.

Within the HMM, these values represent the initial costs for the conventional representation of these technologies. Learning is endogenous in the HMM and specific to each technology. For each doubling of capacity, capital costs are set to decline by 3%. Therefore, cost reductions are scenario-specific. Not all inputs for these technologies need to be updated as some are endogenously calculated within the HMM (e.g., fuel prices, electricity prices, CO_2 emissions, and CO_2 T&S costs).

OL-NEMS Regional Inputs

These adjustments include fuel or feedstock cost, electricity cost, and CO_2 transportation and storage (T&S) costs. Since this regional study primarily impacts the HMM, Natural

Gas Market Module (NGMM), Electricity Market Module (EMM), and Oil & Gas Supply Module (OGSM) in OL-NEMS, the following discussion describes the regionality of the various data flows between them (U.S Energy Information Administration, 2020, 2022b).

Regional Updates for H_2

The HMM uses census regions for fuel and electricity demand and H_2 supply. For example, as seen in Figure 4, the East Coast regionality specified includes census regions 1, 2, and 5. To determine the fuel and electricity demand for the East Coast region, the H_2 demand was restricted to the sum of demand in regions 1, 2, and 5.

For the inputs into the HMM, natural gas and electricity prices are available at the census region level but do not change between states. Therefore, they were used for the East Coast region unchanged. Natural gas and electricity supply can be limited to regions 1, 2, and 5. However, for the BAU scenarios, initial testing shows that the supply constraints for natural gas and electricity will not be reached; thereby, the supply is not restricted.

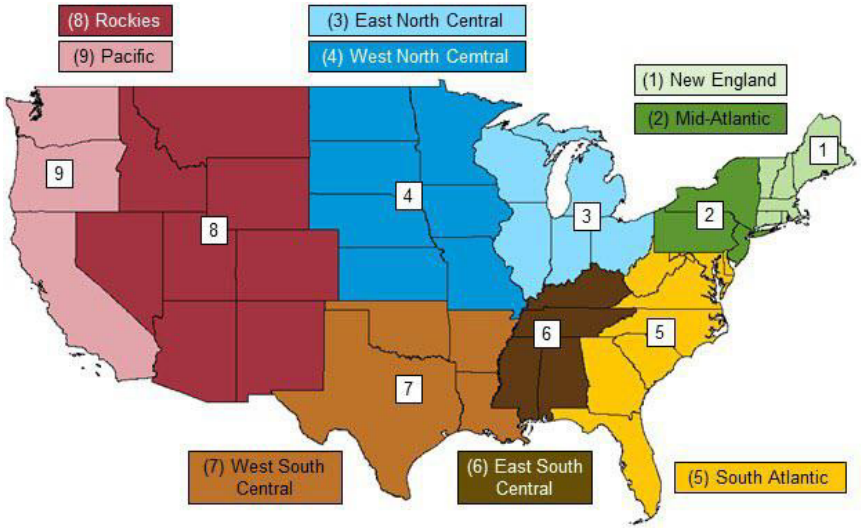


Figure 4. U.S. Census Regions, Numbered (Source: EIA)

Regional Reporting for Natural Gas

Onshore natural gas production is reported by the OGSM at the OGSM region level as seen in Figure 5. The OGSM also reports OGSM district-level natural gas production, which can be used to calculate overall production for the states in the respective region.



Figure 5. Oil and Gas Supply Regions (Source: EIA)

Natural gas prices are reported both at the census and OGSM region level and can be processed to produce a weighted average price for each region. The NGMM reports natural gas pipeline capacities and flows between regions using natural gas regions as shown Figure 6. For example, the New England, Southeast, and Florida regions are all completely within the East Coast region and their capacities are reported directly. All the states except Ohio in the Mid-Atlantic & Ohio region are included, therefore this region's capacity is reported as a proportion benched to current capacity in that region.

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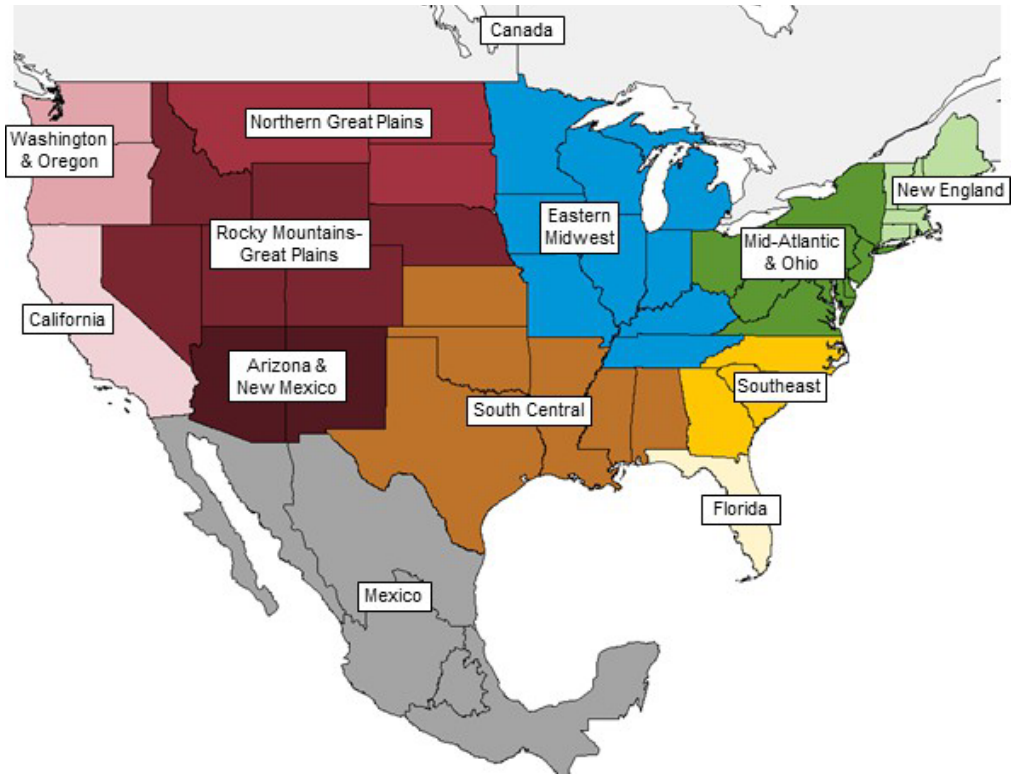


Figure 6. Natural Gas Regions (Source: EIA)

Regional Reporting for Power

OnLocation reports power generation using different technologies including natural gas combined cycle plants. The EMM uses North American Electric Reliability (NERC) regions (Figure 7) for reporting that do not neatly conform to state boundaries. However, which region each state is roughly falling in for most of its generation can be identified. For example, all the states in regions 2, 7, 8, 9, 10, 13, and 14 are part of the East Coast directly, while only part of region 11 (West Virginia and parts of Pennsylvania, Maryland, and Virginia) and 15 (Georgia) are in the East Coast region. For regions 11 and 15, OnLocation uses its share of total generation for reporting (~10% and ~50%, respectively, in 2023).

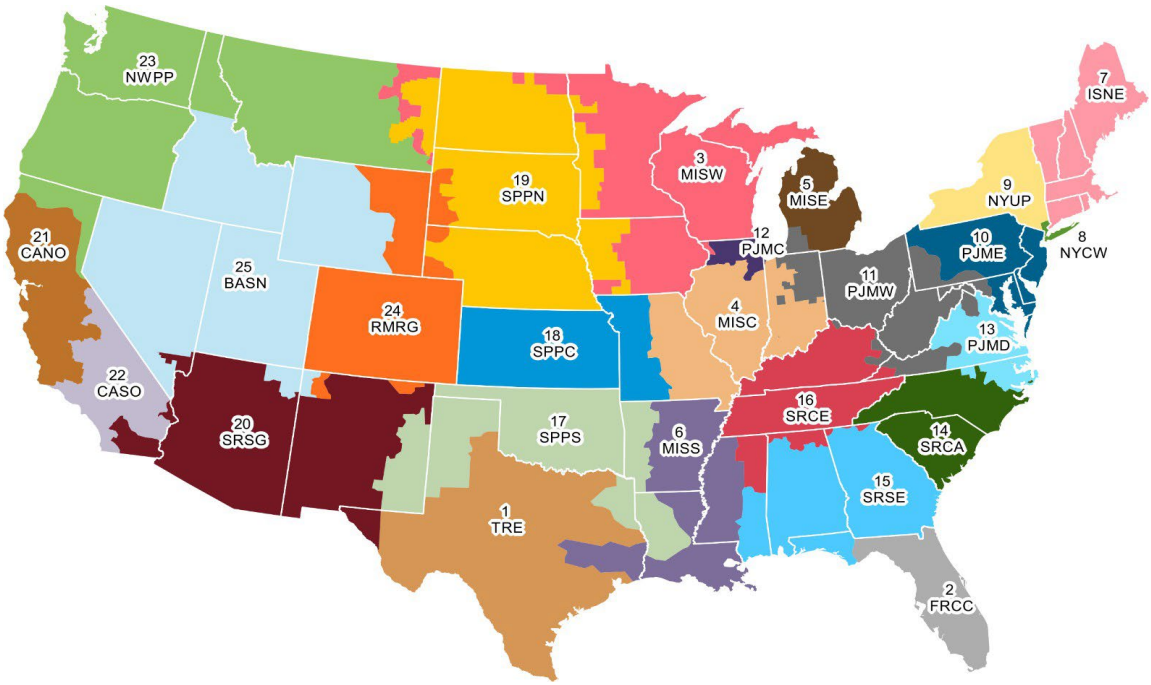


Figure 7. Electricity Supply Regions (Used with Permission from NERC)

Potential Impact of Assumptions on Results

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.

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.

Appendix C: NEMS Outputs

For all scenario outputs, please see "National Case Study NEMS Outputs" on the RAISE website.

Appendix D: Techno-Economic Analysis

Methodology

This section details performance and cost assumptions used to develop all TEA study cases, and methods to ensure consistent assumptions, particularly associated with costs, across all cases to facilitate comparison.

Levelized Cost Metric

The key economic metric for this study is the levelized cost; the revenue required per unit of product produced during the plant's operational life to meet all capital and operational costs. For low-carbon H_2 cases, this is the levelized cost of H_2 (LCOH), in units of \$/kg H_2. For SNG and RNG cases, the metric is the levelized cost of natural gas (LCONG), in units of \$/MMBtu on a higher heating value basis.

The NETL Cost Estimation Methodology QGESS was used to determine the levelized cost. The levelized cost of a product, whether LCOH or LCONG, is the sum of the levelized capital cost (LCC), variable operation and maintenance (O&M) cost (VOMC), fixed O&M cost (FOMC), and fuel or feedstock cost (FC).

$$\text{LCOH or LCONG} = \text{LCC} + \text{VOMC} + \text{FOMC} + \text{FC}$$

The cost metric is reported on a normalized basis, by the annual production rate of the product (i.e., H_2, SNG, or RNG), considering the annual capacity factor (CF) of the plant. The annual production rate is based on the selected plant capacity, which is reported on an hourly rate. The plant capacity and CF of each case is discussed in the following subsections. This report assumes CF and availability are equal for each facility, given that each new plant would be dispatched any time it is available and would be capable of generating the nameplate capacity when online. Additionally, the calculations assume that the CF and availability are constant over the life of the plant, but in practice, a plant will have a higher peak availability to counter lower availability in the first several years of operation" (Lewis, et al., 2022). Thus, the

annual production rates are calculated as a function of the referenced CFs and plant capacities. The formula below shows the annual production rate of the plant, based on the desired units and inclusion of CF.

$$\text{Annual Production Rate (@CF)} = \text{Annual Production Rate (100\% CF)} * \text{CF(\%)}$$
$$= \text{Plant Capacity } \left(\frac{\text{kg}}{\text{day}}\right) * 24\frac{\text{hr}}{\text{day}} * 365\frac{\text{day}}{\text{year}} * \text{CF(\%)}$$

Capital Costs

The levels of capital cost estimated are summarized in Figure 8.

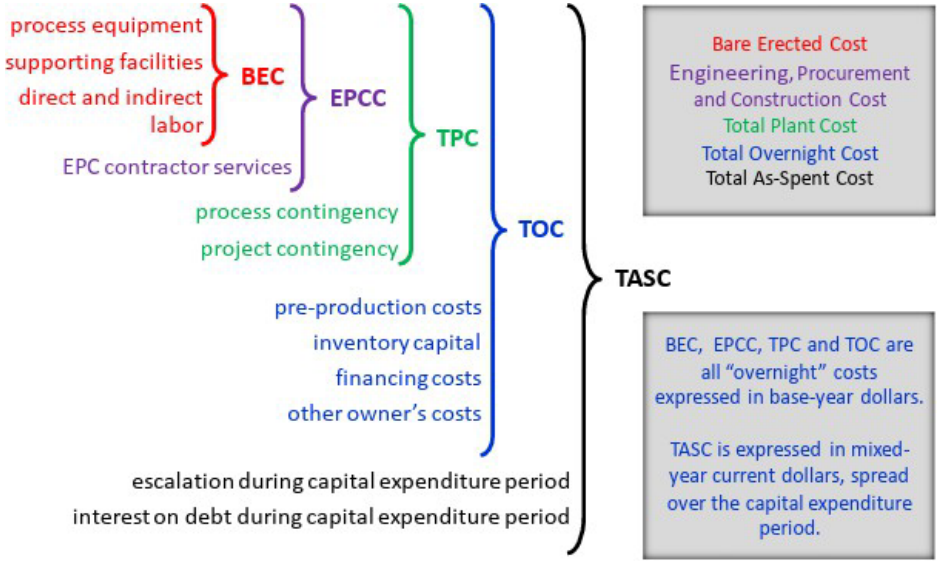


Figure 8. Capital Cost Levels and Their Elements (Source: NETL (Theis, 2019))

A portion of the bare erected cost includes direct and indirect labor costs, which are varied by region based on labor rates. Costs were scaled from reference studies based on the following scaling law with an exponent of 0.6 following the "rule of 6/10th" (Whitesides, 2020) and the ratio of production capacities.

$$Capital\ Cost = Reference\ Cost * \left(\frac{Plant\ Capacity}{Reference\ Capacity}\right)^{0.6}$$

Furthermore, all costs were scaled from their original cost year to the year 2023 via the Chemical Engineering Plant Cost Index (CEPCI).

$$Capital\ Cost_{2023} = Capital\ Cost_{Reference\ Year} * \left(\frac{CEPCI_{2023}}{CEPCI_{Reference\ Year}}\right)$$

Capital costs are levelized over the 30-year plant operating period by applying an industry-specific fixed charge rate (FCR) to the total as-spent cost (TASC). The FCR is a function of debt/equity ratio, interest rate, return on equity, inflation, depreciation, and other financial factors. Estimating the FCR requires multiple assumptions and steps and has not been reproduced here, but the procedure is described in the NETL Cost Estimation Methodology QGESS (Theis, 2019). The FCR determined for this study is 0.0689 based on financial data for the H_2 industry. The capital cost is then normalized by the annual production rate of the product (i.e., H_2, SNG, or RNG), at CF, to determine the LCC.

$$\text{LCC} = \frac{\text{TASC} * \text{FCR}}{\text{Annual Production Rate (100\% CF)} * \text{CF}}$$

Operating Costs

FOMCs are costs that are not proportional to the operating capacity of the plant and include costs for labor, property taxes, and insurance. Labor costs are region-specific. The FOMC is determined by normalizing the cost by the annual production rate.

$$\text{FOMC} = \frac{\text{Fixed O\&M Costs}}{\text{Annual Production Rate (100\% CF)} * \text{CF}}$$

The VOMCs are proportional to the operating capacity of the plant and include electricity costs, consumable costs, waste disposal costs, maintenance material costs, co-product sales, and CO_2 T&S. The coproduct sales considered include carbon

black from the plasma pyrolysis case and electricity exported to the grid in the gasification to RNG cases. Region-specific costs include electricity costs and CO_2 T&S costs.

$$\text{VOMC} = \frac{\text{Variable O\&M Costs (100\% CF)} * \text{CF}}{\text{Annual Production Rate (100\% CF)} * \text{CF}}$$

Feedstocks used in the study include natural gas or RNG for the low-carbon H_2 cases, H_2 and CO_2 for the SNG cases, and MSW or biomass for the RNG cases. The natural gas, H_2 feedstock, and CO_2 feedstock costs are region-specific and the regional availability of RNG, CO_2, MSW, and biomass feedstocks impact plant capacity. The VOMC and FC are determined by multiplying the flow rate by the cost and normalizing by the production rate.

$$\text{FC} = \frac{\text{Annual Fuel Consumption Rate (100\% CF)} * \text{CF} * \text{Fuel Price}}{\text{Annual Production Rate (100\% CF)} * \text{CF}}$$

Facility Scale Considerations

For each fuel case considered in this study, there are inherent differences in the facility economics and emissions reduction potential. Figure 9 summarizes the wide range of costs, carbon intensities, and facility sizes considered for each fuel production pathway.

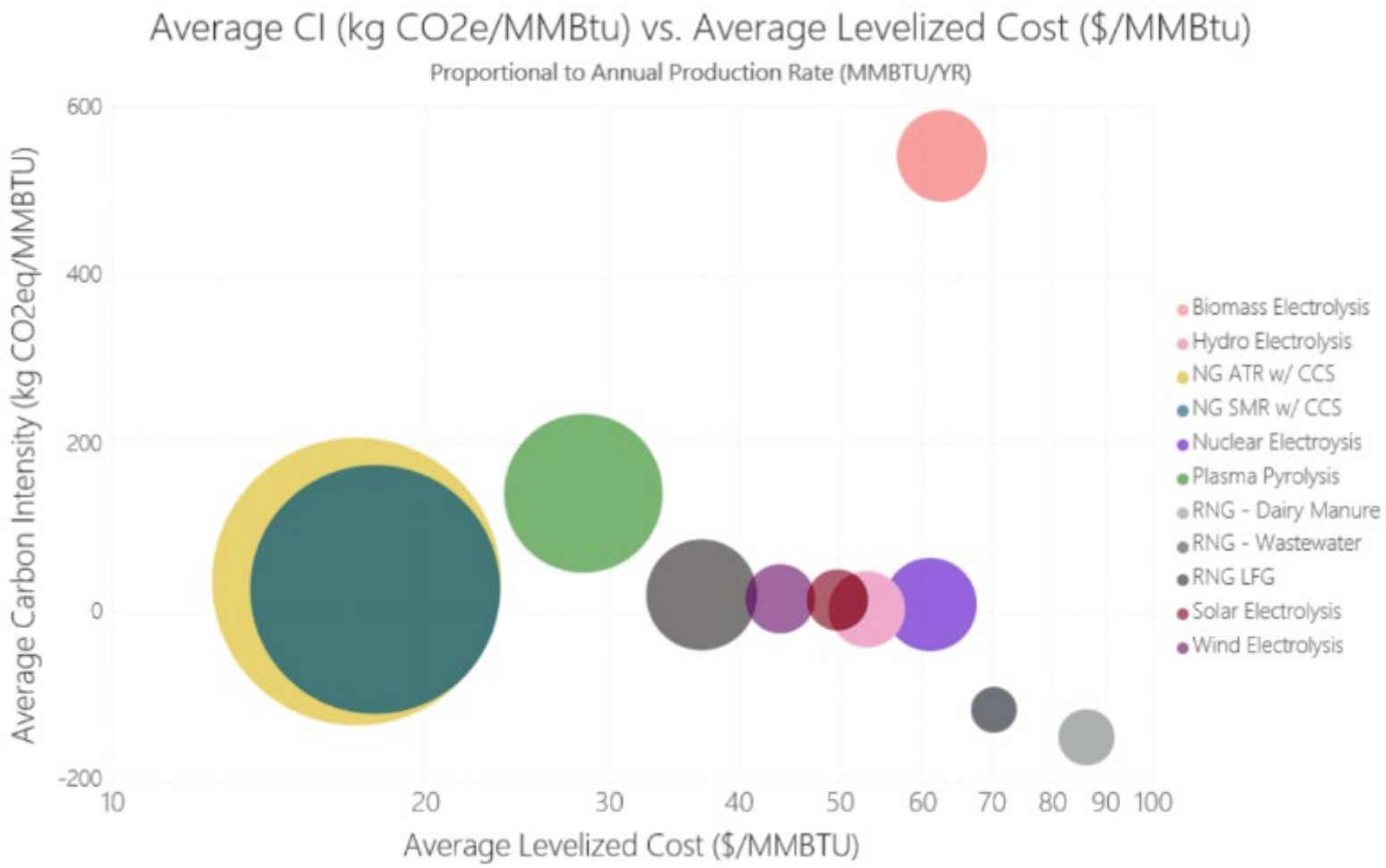


Figure 9. Average Carbon Intensity (CI) (kg CO_2eq/MMBtu) vs. Average Levelized Cost ($/MMBtu)

Given the evolving literature on H_2 and RNG production, this study evaluates technology-specific facility scales and operating conditions to best reflect representative deployment conditions. Inherently, each fuel production technology favors specific facility sizes to optimize economics.

Additionally, each fuel production pathway is anticipated to experience differences in economies of scale, with some production methods more significantly benefiting from increased scaling to achieve optimized levelized costs on a dollar per MMBtu basis. Table 2 summarizes the facility scaling assumptions of each considered production pathway, along with detailed information on the largest reported commercial facility, including planned and operational examples.

Table 2. Facility Scale Considerations

	Estimated Facility Scale Considerations	**Largest Commercial Facility** ***Including planned, operational***
NG ATR w/CCS	▪ Largest facility scale considered ▪ Favorable economies of scale; larger minimum facility scale	Lake Charles Blue H2 Methanol Plant *Louisiana, U.S.* *2X larger than considered facility size*
NG SMR w/ CCS	▪ 2nd largest facility scales considered ▪ Most favorable economies of scale of pathways considered	Air Products Gulf Coast Facility *Texas, U.S.* *40% smaller than considered facility size*
Plasma Pyrolysis	▪ Favorable economies of scale with specific regional opportunities: o (low-cost electricity, solid carbon markets)	Olive Creek 1 Facility *Nebraska, U.S.* *~5 ktpa* *80% smaller than considered facility size*
PEM Electrolysis	▪ Favorable economies of scale with specific regional opportunities: o (low-cost electricity) ▪ Economies of scale benefits less anticipated	Air Liquide PEM Electrolysis Facility *Quebec, Canada* *8.2 metric tons/day* *80% smaller than considered facility size*
Anaerobic Digestion	▪ Regional facility scale opportunities ▪ Economies of scale favorable	Variable scales
Landfill Gas Upgrading	▪ Regional facility scale opportunities ▪ Economies of scale favorable	Archaea Energy Project Assai *Pennsylvania, U.S.* *22,500 scfm*

In some cases, total system adoption blending targets may be more economically achieved by adoption of fuel production pathways with higher levelized costs but regionally opportunistic facility scales and local resources. According to the Department of Energy H2A models, economies of scale benefits are less anticipated with electrolysis and methane pyrolysis as compared to NG SMR and ATR facilities (DOE, 2026). At larger facility scales, the economics for producing H_2 via NG SMR and ATR improve most significantly among considered H_2 production pathways. However, as found by this RAISE study, regional resource availability and favorable economic conditions are deterministic factors in production pathway adoption in each region.

Resource Availability: Methodology and Assumptions

Regional H_2 and RNG production opportunities were evaluated based on availability of key feedstocks and energy sources, including landfilled municipal waste, wastewater biosolids, dairy manure, and renewable electricity potential from solar, wind, hydropower, nuclear, and biomass. Natural gas and electricity affordability, along with regional storage potential, were also assessed where these factors influenced the most economical fuel cases.

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 (EIA, 2025; GTI Energy, 2025; U.S. Department of Agriculture, 2022; U.S. DOE, 2024). These datasets provide the foundation for evaluating the feasibility and scalability of H_2, and RNG. 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.

TEA Assumptions: State Cost Differences

Industrial Natural Gas and Electricity Costs

Regional affordability of industrial electricity, and natural gas play pivotal roles in overall fuel production costs. Figure 10 and Figure 11 summarize the differences across and within regions for industrial natural gas and electricity prices, with boxes representing lower/upper inner quartiles.

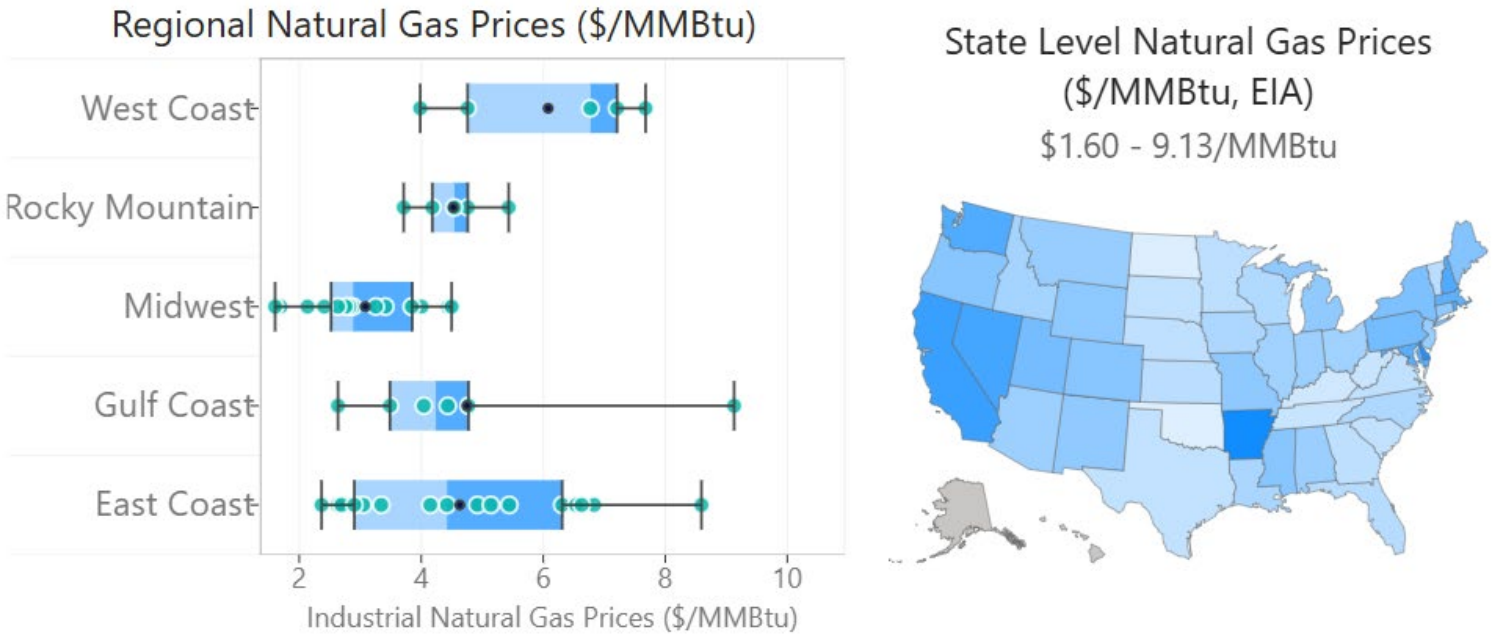


Figure 10. Variability in Natural Gas Prices by State (EIA, 2023)

The most notable cost differences in state-level natural gas prices against electricity are observed in Rhode Island, California, Connecticut, Massachusetts, and New Hampshire.

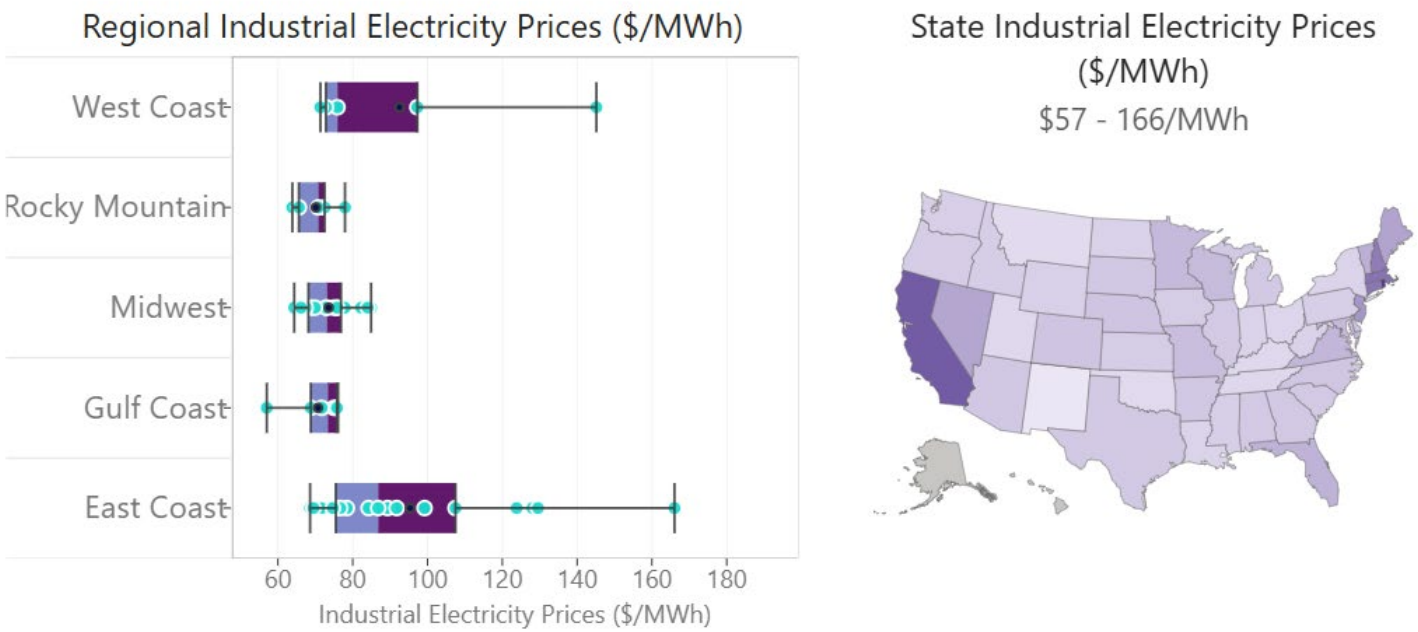


Figure 11. Variability in Electricity Prices ($/MWh) (Industrial, EIA 2023)

Lower levelized electricity costs are generally associated with more competitive levelized costs for NG SMR w/ CCS, NG ATR w/ CCS, and plasma pyrolysis. The lowest average industrial natural gas prices ($3.08/MMBtu) are associated with the Midwest. The East Coast and West Coast experience the highest variability in levelized electricity costs (stdev: $70.54/MWh), whereas the Rocky Mountain experiences the lowest variability among all regions st. dev.: 15.16/MWh). Similarly, the West Coast also experiences some of the highest variability in natural gas prices (range $13.31, st. dev. $3.10), followed by the Gulf Coast. The Rocky Mountain region also experiences the lowest variability in industrial electricity prices among all regions ($1.72/MWh).

Labor Costs

Additionally, there are state level differences in labor rates assumed for the construction and operation of each fuel case facility, which impacts both capital and operating costs.

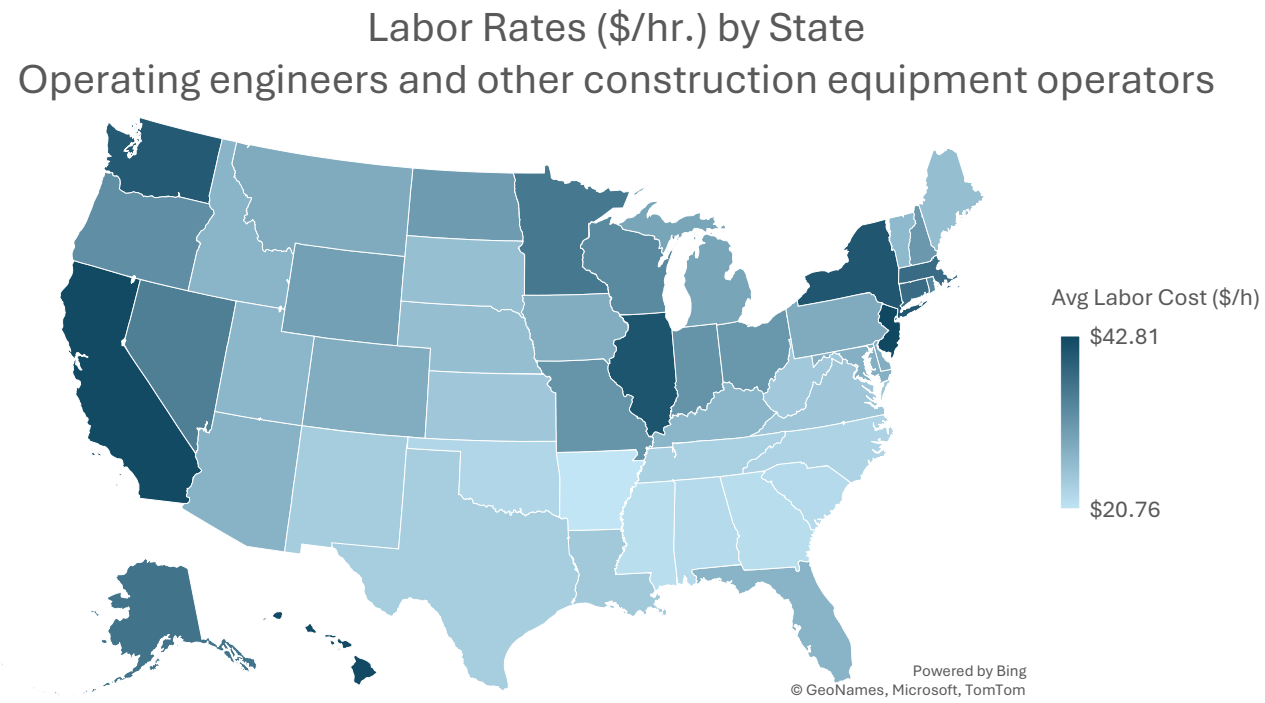


Figure 12. Labor Rates by State

The highest labor rates (>$40/hr.) are observed in New Jersey, California, Illinois, New York, and Washington (Figure 12). These regional variations highlight the importance of scaling production pathways within specific subregions based on cost outlooks, resource availability, and existing infrastructure.

CO_2 Transportation and Storage Assumptions

The CO_2 T&S cost is a summation of the transport cost (via pipeline) and storage cost (in a dedicated saline storage). Each CO_2 pipeline is assumed to be 8-inch diameter and sized to a CO_2 flowrate of 1.7 Mtpa. Table 3 summarizes the CO_2 dedicated pipeline assumptions for each state case levelized cost estimated for the NG SMR w/ CCS and NG ATR w/ CCS cases. The pipeline distances were sourced from the 2024 FECM/NETL CO_2 Capture, Transport and Storage (CTS) Cost Screening Tool. The pipeline distance is assumed to be the distance from each state's capital city to the nearest saline storage location.

Table 3. TEA CO_2 T&S Pipeline Assumptions

Region	State	$/tonne CO_2	Pipeline Distance (mi)	Storage Location
East Coast	Connecticut	28.86	Dedicated; 320	Waste Gate1
East Coast	Delaware	19.51	Dedicated; 70	Waste Gate1
East Coast	Florida	24.75	Dedicated; 40	Lower Tuscaloosa5
East Coast	Georgia	26.51	Dedicated; 210	Lower Tuscaloosa5
East Coast	Maine	44.47	Dedicated; 570	Waste Gate1
East Coast	Maryland	18.53	Dedicated; 80	Waste Gate1
East Coast	Massachusetts	38.38	Dedicated; 400	Waste Gate1
East Coast	New Hampshire	39.32	Dedicated; 440	Waste Gate1
East Coast	New Jersey	25.00	Dedicated; 160	Waste Gate1
East Coast	New York	25.93	Dedicated; 350	Waste Gate1
East Coast	North Carolina	37.44	Dedicated; 260	Waste Gate1
East Coast	Pennsylvania	21.52	Dedicated; 170	Waste Gate1
East Coast	Rhode Island	35.09	Dedicated; 360	Waste Gate1
East Coast	South Carolina	34.45	Dedicated; 320	Lower Tuscaloosa5
East Coast	Vermont	43.07	Dedicated; 490	Waste Gate1

East Coast	Virginia	20.02	Dedicated; 130	Waste Gate1
East Coast	West Virginia	29.14	Dedicated; 180	Mount Simon10
Gulf Coast	Alabama	27.00	Dedicated; 80	Lower Tuscaloosa1
Gulf Coast	Arkansas	28.02	Dedicated; 220	Lower Tuscaloosa6
Gulf Coast	Louisiana	18.24	Dedicated; 50	Lower Tuscaloosa7
Gulf Coast	Mississippi	13.38	Dedicated; 20	Lower Tuscaloosa8
Gulf Coast	New Mexico	18.64	Dedicated; 120	Entrada9
Gulf Coast	Texas	9.54	Dedicated; 140	Frio1
Midwest	Illinois	19.42	Dedicated; 30	Mount Simon3
Midwest	Indiana	11.72	Dedicated; 30	Mount Simon6
Midwest	Iowa	28.39	Dedicated; 280	Mount Simon3
Midwest	Kansas	18.57	Dedicated; 230	Arbuckle4
Midwest	Kentucky	18.15	Dedicated; 20	Mount Simon11
Midwest	Michigan	21.93	Dedicated; 80	Mount Simon7
Midwest	Minnesota	38.83	Dedicated; 350	Red River1
Midwest	Missouri	30.32	Dedicated; 200	Mount Simon3
Midwest	Nebraska	32.24	Dedicated; 280	Arbuckle4
Midwest	North Dakota	24.17	Dedicated; 60	Red River1
Midwest	Ohio	21.87	Dedicated; 50	Mount Simon10
Midwest	Oklahoma	20.75	Dedicated; 100	Arbuckle1
Midwest	South Dakota	35.79	Dedicated; 150	InyanKara2
Midwest	Tennessee	22.51	Dedicated; 100	Knox5
Midwest	Wisconsin	21.43	Dedicated; 210	Mount Simon7
Rocky Mountain	Colorado	24.69	Dedicated; 110	Dakota2
Rocky Mountain	Idaho	35.22	Dedicated; 340	Tensleep4

Rocky Mountain	Montana	16.96	Dedicated; 260	Frontier3
Rocky Mountain	Utah	16.90	Dedicated; 50	Tensleep5
Rocky Mountain	Wyoming	19.79	Dedicated; 40	Entrada6
West Coast	Arizona	33.72	Dedicated; 380	Repetto1
West Coast	California	10.91	Dedicated; 40	Mokelumne River1
West Coast	Nevada	26.04	Dedicated; 130	Forbes1
West Coast	Oregon	40.14	Dedicated; 420	Forbes1
West Coast	Washington	48.96	Dedicated; 580	Forbes1

Differences in Levelized Costs – RNG Dairy Manure vs. Wastewater

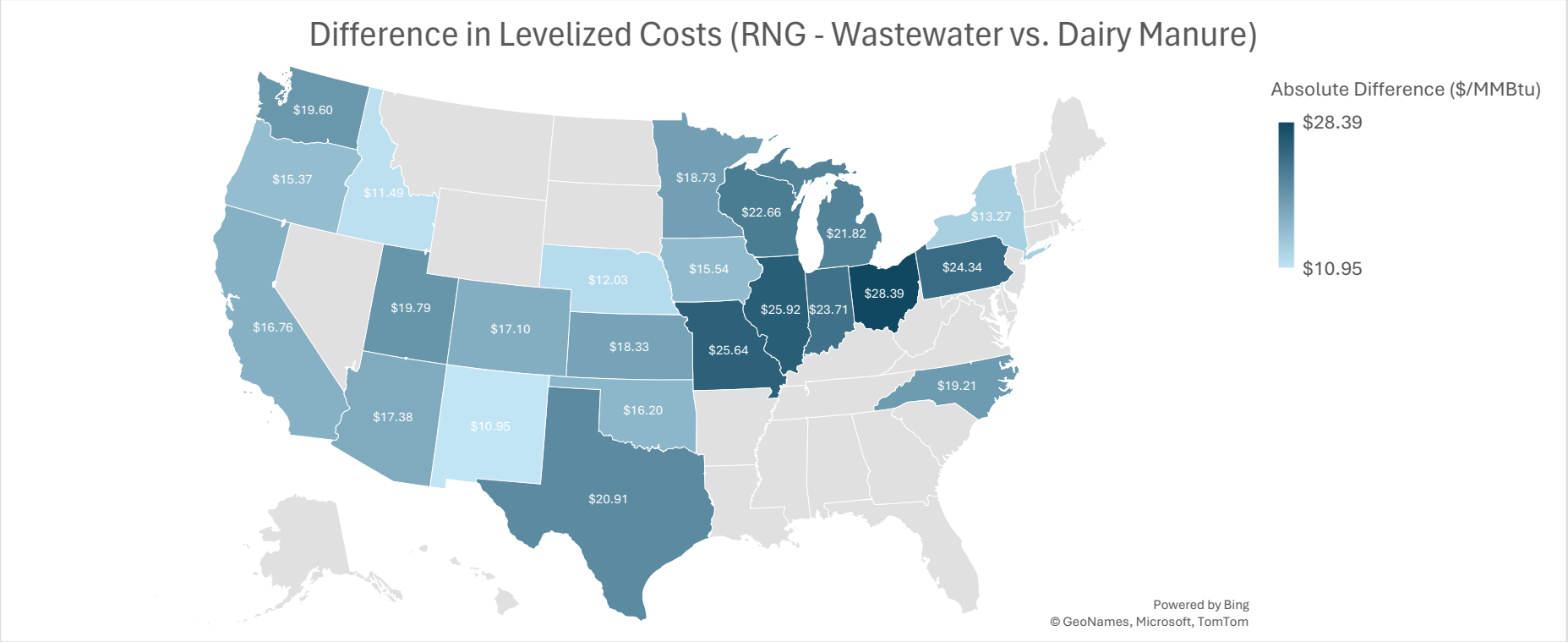


Figure 13. Cost Differences in RNG via Wastewater vs. Dairy Manure

RNG produced from wastewater is estimated to have lower levelized costs across all state cases evaluated. New York, Idaho, and New Mexico show the smallest differences in levelized costs between wastewater-derived RNG and dairy manure-derived RNG, with gaps of less than $15/MMBtu. In contrast, Wisconsin, Indiana, Pennsylvania, Missouri, Illinois, and Ohio exhibit the largest differences, with cost gaps approaching $25/MMBtu. These cost differentials persist even in cases where the dairy manure facilities have larger production capacities than the wastewater facilities.

Additional Assumptions

The National Energy Technology Laboratory's (NETL) Quality Guidelines for Energy System Studies (QGESS) provided the basis for the cost estimation methodology and has been consistently utilized throughout various referenced NETL studies.

The electricity costs reported are estimated unweighted levelized costs of electricity (LCOEs) for new resources entering service in 2027, and more assumptions for the LCOE calculation can be found in the AEO Levelized Costs report (U.S Energy Information Administration, 2022a).

Summary of State-Level Technoeconomic Assumptions

RNG facility capacities are also estimated as a function of in-state resources. For instance, the facility capacities range from 1 to 185 MMBtu/hr whereas RNG Dairy manure cases possess facility capacities range from 13 to 330 MMBtu/hr. The greatest capacity difference assumptions are applied for New York and Iowa (increased capacities assumed for RNG via wastewater) and Illinois and Ohio (increased capacities assumed for RNG via dairy manure). However, despite these capacity differences, several cost components (capital, variable O&M) more significantly contribute to the costs observed for wastewater and dairy manure 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. State specific PEM electrolysis facility capacities are additionally approximated based on in-state resources for renewable electricity generation via solar, wind, nuclear and biomass. However, for NG ATR w/ CCS and NG SMR w/ CCS state levelized costs, facility scales are not varied.

To best approximate state specific costs, state-level cost data was utilized, including EIA prices for industrial end user natural gas, and electricity, as well as May 2023 U.S. BLS labor rates for operating engineers and other construction equipment operators.

MSW Landfills

Unlike other fuel cases considered in this study, the feedstock (municipal solid waste landfill gas) for upgraded LFG RNG is intrinsically linked to landfill size and age, which determines the recoverable methane over the lifetime of the landfill. In the U.S., the majority of MSW landfills (>75%) are installed with gas collection systems, which enable the recovery of landfill gas. Many of these MSW landfills either flare landfill gas, produce onsite electricity, produce compressed natural gas, or interconnect to natural gas infrastructure to deliver RNG.

Additional Considerations of Cost Outlooks

MSW landfill tipping fees can signal a stronger opportunity for MSW landfills to develop landfill gas collection and upgrading facilities. According to the Environmental Research and Education Foundation, the highest MSW landfill tipping fees are experienced in the Northeast and West Coast regions (~$60 to 80/ton, 2023), whereas tipping fees are lowest in the Southeast and Southcentral regions ($43 to 45/ton, 2023) (Environmental Research & Education Foundation, 2023).

Methane Pyrolysis

Local markets for solid carbon can also improve outlooks for methane pyrolysis. Carbon black is a shelf stable co-product of methane pyrolysis but must be stored in specific conditions to ensure quality over time. Based on current reported market rates, the methane pyrolysis facilities are assumed to sell solid carbon black at a rate of $417/ton produced, which is 25% of the reported market value of carbon black in January 2023 (Business Analytiq, 2026).

Potential Impact of Assumptions on Results

The TEA applies assumptions supported by literature and is constrained by the NETL calculation methodology. There are potential gaps in each TEA where low carbon fuel production technologies are still under research, and long-term costs of these pathways are uncertain.

Some identified potential opportunities for cost reductions:

- The impacts of regionally high electricity costs on O&M costs can be avoided if the process permits some partial use of the fuel produced to power the facility through combined heat and power systems, boilers, and internal combustion engines.
- This study has conservatively assumed available in-state resources for RNG production, excluding co-digestion, and larger state-of-the-art facilities. Biological waste diversion programs, namely food waste and pulp/paper waste are not considered but are often suitable for co-digestion facilities with more common RNG feedstocks.

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., New York) could face higher feedstock costs, while emerging fuels (e.g., H_2) may reduce RNG competitiveness.
- 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.

Appendix E: Lifecycle Analysis

Methodology

The following sections discuss how the various models used have been created originally and modified as needed for use in this project.

Life Cycle Framework of the OHI Toolkit

The OHI toolkit, a joint effort of GTI Energy, NETL, and S&P Global, was released in 2024 and can estimate the GHG intensity of producing H_2 from 13 different technology pathways and in nearly any part of the world. The OHI toolkit is a life cycle-based model and represents cradle-to-gate emissions of producing 1 kg of H_2 in all pathways (GTI Energy, 2025). Results are aggregated consistently into categories of H_2 Production, Upstream Electricity, Upstream Natural Gas, Upstream Biomass, Upstream RNG, Upstream LNG, Carbon Management, and Co-Product Management. Some pathways do not have any emissions associated with these categories (e.g., if RNG or liquified natural gas [LNG] is not used, or if there are no co- products). Energy is modeled on a lower heating value basis, and GHG emissions are first estimated on a speciated basis (i.e., of CO_2, CH_4, and nitrous oxide separately) before being converted, for reporting, to CO_2-equivalent (CO_2e) emissions by using Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6) 100-year values. For this study, in OHI custom input and outputs were utilized for all hydrogen pathways. However, default background/advanced inputs were not altered unless otherwise specified. For RNG, default inputs and output were maintained in both OHI and R&D GREET.

Emission Intensity of Upstream Natural Gas Consumption

The first key input that is expected to lead to variability in regional modeling results is the GHG intensity of upstream natural gas consumption used at the production site. A recently released LCA baseline study by NETL of U.S. natural gas (Khutal et al., 2024) and associated model and results is the latest in a line of studies developed by DOE over the past

decade that estimate the total life cycle environmental flows associated with producing and using natural gas from various techno-basins in the U.S. The scope of activities in this model includes all known major activities in the natural gas value chain, e.g., production, gathering and boosting, processing, transmission, storage, and distribution (when applicable). The model is a documented, bottom-up inventory of hundreds of known processes across the natural gas supply chain that lead to GHG and other air emissions (such as those that use energy, or the use of compression and leaky seals). Given the bottom-up nature of the model, individual data sources (such as EPA GHGRP (EPA, 2024)) and other scientific literature form the basis of the emissions estimates. The bottom-up representation differs from those of top-down studies that use aerial or other measurements to detect GHG emissions and that do not attribute emissions to detailed fuels (oil or gas) and to specific stages (e.g., production, processing). Overall model results are provided for each of the six individual natural gas production stages listed above and aggregated for delivery of U.S. average natural gas to large-scale consumers (at or near transmission pipelines) as well as to local consumers (through the distribution system) representative of the year 2020. In addition, the model provides mean and 95% confidence interval results for the delivery of natural gas from various techno-basins to six regions defined in previous GTI Energy studies, as shown in Figure 14. This model estimates CH_4 leakage in the U.S. natural gas system via a bottom-up approach of equipment and sources in each basin, with in an overall average CH_4 emissions rate of 0.56%.

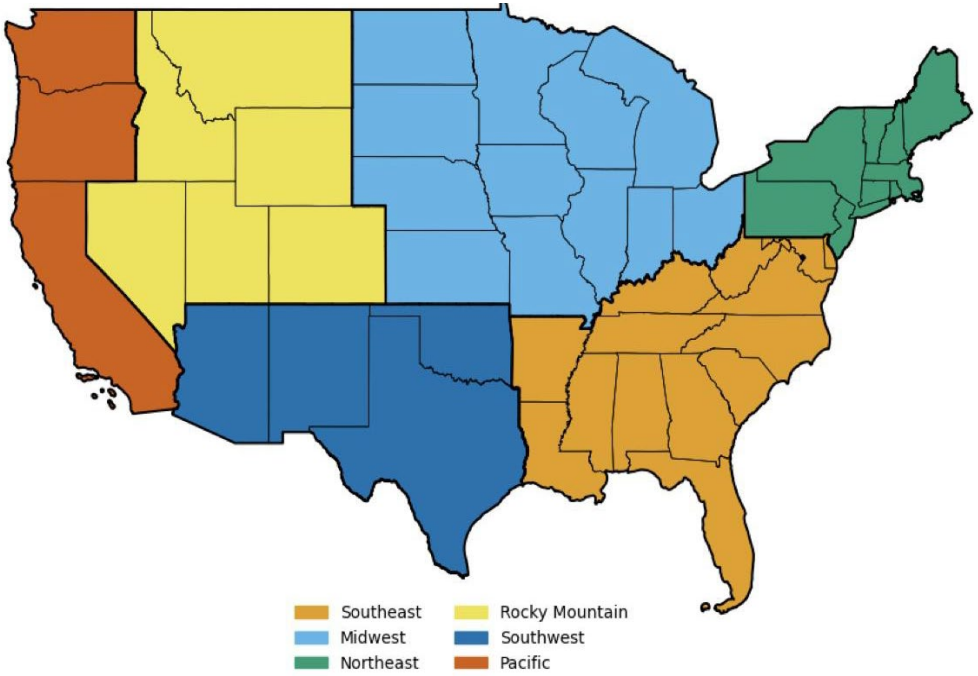


Figure 14. Delivery Regions for Natural Gas in the U.S. Used in the NETL NG Baseline (Khutal, et al., 2024)

While the regional boundaries between the NETL/GTI and PADD definitions are generally similar, there are differences. To meet the requirements of the project, the values for the regions were found by leveraging results from the NETL/GTI Energy production and delivery regions. The production and delivery regions were specified for each state in OHI to generate state specific upstream natural gas emissions intensity as shown in Table 4.

Table 4. Natural Gas Basin and State-Level GHG Intensities

Region	State	Production Region	Delivery Region	kg CO_2e/kg NG
East Coast	Connecticut	Appalachian	Northeast	0.31
	Delaware	Appalachian	Southeast	0.35
	D.C	Appalachian	Southeast	0.35
	Florida	Appalachian	Southeast	0.35
	Georgia	Appalachian	Southeast	0.35
	Maine	Appalachian	Northeast	0.31
	Maryland	Appalachian	Southeast	0.35
	Massachusetts	Appalachian	Northeast	0.31
	New Hampshire	Appalachian	Northeast	0.31
	New Jersey	Appalachian	Northeast	0.31
	New York	Appalachian	Northeast	0.31
	North Carolina	Appalachian	Southeast	0.35
	Pennsylvania	Appalachian	Northeast	0.31
	Rhode Island	Appalachian	Northeast	0.31
	South Carolina	Appalachian	Southeast	0.35
	Vermont	Appalachian	Northeast	0.31
	Virginia	Appalachian	Southeast	0.35
	West Virginia	Appalachian	Southeast	0.35
Midwest	Illinois	Appalachian	Midwest	0.32
	Indiana	Appalachian	Midwest	0.32
	Iowa	Anadarko	Midwest	0.80
	Kansas	Anadarko	Midwest	0.80
	Kentucky	Appalachian	Midwest	0.32
	Michigan	Appalachian	Midwest	0.32
	Minnesota	Anadarko	Midwest	0.80

	Missouri	Anadarko	Midwest	0.80
	Nebraska	Anadarko	Midwest	0.80
	North Dakota	Anadarko	Midwest	0.80
	Ohio	Appalachian	Midwest	0.32
	Oklahoma	Anadarko	Southwest	0.58
	South Dakota	Anadarko	Midwest	0.8
	Tennessee	Appalachian	Southeast	0.35
	Wisconsin	Appalachian	Midwest	0.32
Gulf Coast	Alabama	Gulf	Southeast (Gulf Coast)	0.64
	Arkansas	Permian	Southeast (Midcontinent/Appalachia)	0.84
	Louisiana	Gulf	Southeast (Gulf Coast)	0.64
	Mississippi	Gulf	Southeast (Gulf Coast)	0.64
	New Mexico	Permian	Southwest (Permian Basin)	0.55
	Texas	Permian	Southwest (Permian Basin)	0.55
Rocky Mountain	Colorado	Piceance	Rocky Mountain	0.4
	Idaho	Green River	Rocky Mountain	0.59
	Montana	Green River	Rocky Mountain	0.59
	Utah	Uinta	Rocky Mountain	1.87
	Wyoming	Green River	Rocky Mountain	0.59
West Coast	Arizona	San Juan	Southwest	1.65
	California	Permian	Pacific	0.51
	Nevada	Permian	Pacific	0.51
	Oregon	Green River	Pacific	0.73
	Washington	Green River	Pacific	0.73

Emission Intensity of Upstream Electricity Consumption

The second key input that is known to significantly vary by region is the life cycle GHG intensity of grid electricity consumed at the production site. This includes the life cycle of electricity from the upstream production of fuels, transport of fuels to a production site, and generation, transmission, and distribution of the electricity.

Past work by DOE and EPA created a series of electricity baseline reports and the Electricity framework. These studies estimate various environmental flows, such as emissions of each species of GHG and other air and water emissions. Results from these efforts were published as a publicly available Grid Mix Explorer tool, and publicly available source code for generating custom grid mixes (EPA, n.d.). Additionally, as a part of the analysis done in prior work (Josh Redublo et al., n.d.) each state in the dataset was first assigned to a PADD region and a Federal Energy Regulatory Commission (FERC) electricity region based on historical regulatory boundaries. This was an important source to help inform the mapping of Balancing Authorities to specific states.

Similar to the mapping of delivered natural gas from the NETL/GTI Energy study regions to the PADD regions, values from the FERC regions will be aligned with the PADD regions based on state electricity consumption data from EIA. EIA's Electricity Data Browser is a comprehensive tool that offers detailed data on electricity generation, consumption, and other related metrics across various regions and timeframes.

A weighted GHG intensity for each state is found by combining the GHG intensities of states via a consumption-weighted average, as in the following equation:

$$\text{Weighted GHG Intensity} = \frac{\sum(E_i \times I_i)}{\sum E_i}$$

Where E_i is the electricity consumption of state i (MWh) and I_i is the GHG intensity of state i in kg CO_2e/MWh. In general, since the intensities only vary by about 15% between adjacent regions (and all are within about 20% of the U.S. average), the re-mapping to PADD regions is not expected to significantly change the results.

This same method will be used to derive region-specific upstream electricity GHG intensity values to be used as inputs of the carbon intensity estimates for all regions and all pathways in the study. Detailed data is demonstrated in Table 5.

Table 5. Electricity Balancing Authority (BA) and State-Level GHG Intensities

Region	State	Balancing Authority	Annual Net Generation TWh	Annual Net Generation MWh	BA Intensity (kg CO_2e/MWh)	State Intensity (kg CO_2e/MWh)
East Coast	Connecticut	ISO-NE	102.14	102140000	247.33	247.33
	Delaware	PJM	822.99	822990000	326.32	326.32
	D.C	PJM	822.99	822990000	326.32	326.32
	Florida	Duke Energy Florida	46.93	46930000	441.26	367.9646294
		Florida Power & Light Company	139.87	139870000	271.52	
		Florida Municipal Power Pool	13.63	13630000	524.5	
		JEA	9.82	9820000	531.53	
		Seminole Electric Cooperative	12.63	12630000	550.52	
		Southern Co	250.51	250510000	383.95	
	Georgia	Southern Co	250.51	250510000	383.95	343.4654148
		Tennessee Valley Authority	165	165000000	282	
	Maine	ISO-NE	102.14	102140000	247.33	247.33
	Maryland	PJM	822.99	822990000	326.32	326.32

	Massachusetts	ISO-NE	102.14	102140000	247.33	247.33
	New Hampshire	ISO-NE	102.14	102140000	247.33	247.33
	New Jersey	PJM	822.99	822990000	326.32	326.32
	New York	NYISO	129.71	129710000	218.02	218.02
	North Carolina	Duke Energy Carolinas	108.36	108360000	220.58	307.6757854
		Duke Energy Progress East	66.95	66950000	219.64	
		PJM	822.99	822990000	326.32	
		Duke Energy Progress West	0.04	40000	0	
	Pennsylvania	PJM	822.99	822990000	326.32	326.32
	Rhode Island	ISO-NE	102.14	102140000	247.33	247.33
	South Carolina	Duke Energy Carolinas	108.26	108260000	220.58	220.58
	Vermont	ISO-NE	102.14	102140000	247.33	247.33
	Virginia	PJM	822.99	822990000	326.32	318.9183057
		Tennessee Valley Authority	165	165000000	282	
	West Virginia	PJM	822.99	822990000	326.32	326.32
Midwest	Illinois	MISO	653	653000000	541	421.2976353
		PJM	822.99	822990000	326.32	
	Indiana	MISO	653	653000000	541	421.2976353
		PJM	822.99	822990000	326.32	
	Iowa	MISO	653	653000000	541	523.4714747
		SPP	276	276000000	482	
	Kansas	SPP	276	276000000	482	482
	Kentucky	MISO	653	653000000	541	407.2913892

		PJM	822.99	822990000	326.32	
		Tennessee Valley Authority	165	165000000	282	
	Michigan	MISO	653	653000000	541	421.2976353
		PJM	822.99	822990000	326.32	
	Minnesota	MISO	653	653000000	541	523.4714747
		SPP	276	276000000	482	
	Missouri	MISO	653	653000000	541	523.4714747
		SPP	276	276000000	482	
	Nebraska	SPP	276	276000000	482	482
	North Dakota	MISO	653	653000000	541	523.4714747
		SPP	276	276000000	482	
	Ohio	PJM	822.99	822990000	326.32	326.32
	Oklahoma	SPP	276	276000000	482	482
	South Dakota	MISO	653	653000000	541	523.4714747
		SPP	276	276000000	482	
	Tennessee	PJM	822.99	822990000	326.32	318.9183057
		Tennessee Valley Authority	165	165000000	282	
	Wisconsin	MISO	653	653000000	541	541
Gulf Coast	Alabama	SERC	251	251000000	431	475.20
		MISO	653	653000000	541	
		Tennessee Valley Authority	165	165000000	282	
	Arkansas	MISO	653	653000000	541	523.47
		SPP	276	276000000	482	
	Louisiana	MISO	653	653000000	541	523.47
		SPP- Western Louisiana	276	276000000	482	

	Mississippi	MISO	653	653000000	541	510.46
		SERC	251	251000000	431	
	New Mexico	SPP	276	276000000	482	532.56
		WAPA - Rocky Mountain	38	38000000	875	
		Public Service Company New Mexico	17	17000000	588	
	Texas	ERCOT	470	470000000	428	428.00
Rocky Mountains	Colorado	PACE	61.1	61100000	676.3	863.2483568
		WECC	940	940000000	875.4	
	Idaho	PACE	61.1	61100000	676.3	863.2483568
		WECC	940	940000000	875.4	
	Montana	MISO	653	653000000	541	736.0322411
		WECC	940	940000000	875.4	
		PACE	61.1	61100000	676.3	
	Utah	PACE	61.1	61100000	676.3	863.2483568
		WECC	940	940000000	875.4	
	Wyoming	WECC	940	940000000	875.4	863.2483568
		PACE	61.1	61100000	676.3	
West Coast	Alaska	CEA	7	7000000	322	322
	Arizona	CISO	176	176000000	271.9	334.4423729
		APS	24.6	24600000	781.9	
	California	CISO	176	176000000	271.9	209.3898386
		PACW	8.1	8100000	139.2	
		BPAT	88.5	88500000	91.5	
	Hawaii	HECO	9.3	9300000	510	510
	Nevada	NPC	17.4	17400000	436.2	436.2
	Oregon	BPAT	88.5	88500000	91.5	95.49968944
		PACW	8.1	8100000	139.2	

	Washington	BPAT	88.5	88500000	91.5	95.49968944
		PACW	8.1	8100000	139.2	

Detailed Inputs in OHI Toolkit

The following tables provide the detailed assumptions used within the OHI toolkit for the H_2 production pathways, showing all detailed and customized assumptions used. Subsequent sections show details for RNG modeling. Note that there are various rows without explicit entries (e.g., "Not Selected") that are maintained here for transparency to aid in replication efforts, e.g., to duplicate results in the OHI tool and ensure the right parameters are used or selected in the commensurate cells of the tool.

Table 6. Assumptions Used for H_2 Production Pathways in OHI Toolkit

NG-fed w/ CCS		
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid electricity	
Where does captured CO_2 go downstream?	Saline Aquifer Storage	
Where is CO_2 captured in the system?	From shifted gas using MDEA and flue gas MEA (90% net capture)	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	

Process Definition		
Natural Gas	3.73	kg
Water	4.9	kg
Embodied Emissions	1.45E-04	kg CO_2e
Captured CO_2	9.81	kg
Carbon Dioxide	1.09	kg
Electricity Co-product	0.05	kWh
Default Electricity Mix		
Biomass	0.70%	
Coal	17.20%	
Geothermal	0.50%	
Hydroelectric	9.80%	
Natural Gas	40.00%	
Nuclear	19.70%	
Oil	0.10%	

Solar Photovoltaic	3.80%	
Solar Thermal	0.10%	
Storage	0.00%	
Wind	8.20%	
Other	0.00%	
RNG Customization Type	Default	
Carbon Management Type	Default	
Natural Gas		
Country where natural gas is being sources from	United States of America (the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southeast or Northeast based on the state the scenario is run for	

NG-fed ATR w/CCS		
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid electricity	
Is there a nitrogen co-product?	Yes	
Where does captured CO_2 go downstream?	Saline Aquifer Storage	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Electricity	4.006545455	kWh
Natural Gas	3.524727273	kg
Water	24.35247273	kg
Embodied Emissions	0.000151023	kg CO_2e
Captured CO_2	8.81	kg
Carbon Dioxide	0.52	kg
Nitrogen (co-product)	14.65	kg

Grid Mix Type	Conventional Mix	
Default Electricity Mix		
Biomass	0.6%	
Coal	16.9%	
Geothermal	0.0%	
Hydroelectric	1.3%	
Natural Gas	41.1%	
Nuclear	35.8%	
Oil	0.1%	
Solar Photovoltaic	0.8%	
Solar Thermal	0.0%	
Storage	0.0%	
Wind	3.4%	
Other	0.0%	
Carbon Management Type	0.6%	

Natural Gas		
Country where natural gas is being sources from	United States of America (the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Include avoided emissions?	Yes	
NG Plasma Pyrolysis	Plasma Pyrolysis	
What is used for facility heating?	Natural Gas	
Is there a co-product?	No	
Process Definition		
Inputs		
Electricity	0.0403	kWh
Natural Gas	5.43	kg

Water	252.15	kg
Outputs		
Carbon Dioxide	2.61	kg
Methane	0.03	kg
Nitrous Oxide	0	kg
H_2 (fugitive)	0	kg

Table 8. Assumptions Used for H_2 Production Pathways in OHI Toolkit, Continued

PEM Electrolysis with Solar		
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		

Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		
Biomass	0.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	0.00%	
Natural Gas	0.00%	
Nuclear	0.00%	

Oil	0.00%	
Solar Photovoltaic	50.00%	
Solar Thermal	50.00%	
Storage	0.00%	
Wind	0.00%	
Other	0.00%	
Natural Gas		
Country where natural gas is being sources from	United States of America (the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		
Include avoided emissions?	Yes	

PEM Electrolysis with Wind		
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg

Electricity		kg
Default Electricity Mix		
Biomass	0.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	0.00%	
Natural Gas	0.00%	
Nuclear	0.00%	
Oil	0.00%	
Solar Photovoltaic	0.00%	
Solar Thermal	0.00%	
Storage	0.00%	
Wind	100.00%	
Other	0.00%	
Natural Gas		

Country where natural gas is being sources from	United States of America (the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		
Include avoided emissions?	Yes	
PEM Electrolysis with Nuclear		
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		

Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		
Biomass	0.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	0.00%	
Natural Gas	0.00%	

Nuclear	100.00%	
Oil	0.00%	
Solar Photovoltaic	0.00%	
Solar Thermal	0.00%	
Storage	0.00%	
Wind	0.00%	
Other	0.00%	
Natural Gas		
Country where natural gas is being sources from	United States of America (the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		

Include avoided emissions?	Yes	
PEM Electrolysis with Hydroelectric		
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	

Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		
Biomass	0.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	100.00%	
Natural Gas	0.00%	
Nuclear	0.00%	
Oil	0.00%	
Solar Photovoltaic	0.00%	
Solar Thermal	0.00%	
Storage	0.00%	
Wind	0.00%	
Other	0.00%	

Natural Gas		
Country where natural gas is being sources from	United States of America (the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		
Include avoided emissions?	Yes	
PEM Electrolysis with Bioelectric		
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	

Process Definition		
Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		
Biomass	100.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	0.00%	

Natural Gas	0.00%	
Nuclear	0.00%	
Oil	0.00%	
Solar Photovoltaic	0.00%	
Solar Thermal	0.00%	
Storage	0.00%	
Wind	0.00%	
Other	0.00%	
Natural Gas		
Country where natural gas is being sources from	United States of America (the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	

Results		
Include avoided emissions?	Yes	

RNG-Specific Modeling Details

Table 9 summarizes the specific parameters used for analysis of RNG for the cited work above. The report incorporates process data from R&D GREET (landfill) and OHI (wastewater and animal manure) while modeling is conducted using IPCC AR6 100-year characterization factors (Argonne National Laboratory, 2026).

Table 9. RNG-Specific Modeling Details

Waste Water (OHI)		
Sludge_input	86.22	kg/kg-biogas
Electricity_input	0.2145	kWh/kg-biogas
Natural gas input	0.0166	kg-NG/kg-biogas
Leakage CH4	0.0040	kg-CH_4/kg biogas
Digestate waste output	8.0424	kg-residue/kg-biogas
Biogas energy content	0.0455	kg/MJ
Animal Manure (OHI)		
Sludge input	48.4543	kg/kg-biogas
Electricity input	0.3125	kWh/kg-biogas
Natural gas input	0.0630	kg-NG/kg-biogas
Leakage CH4	0.0056	kg/kg-biogas
Digestate waste output	3.8672	kg/kg-biogas
Biogas energy content	0.0455	kg/MJ-biogas
Landfill Gas (GREET)		
Electricity	54,343	Btu/mmBtu

Natural Gas	38,944	Btu/mmBtu
Water	6.57	Gallons/mmBtu
Feed loss	28,680	Btu/mmBtu

Potential Impact of Assumptions on Results

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

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 carbon intensity values.

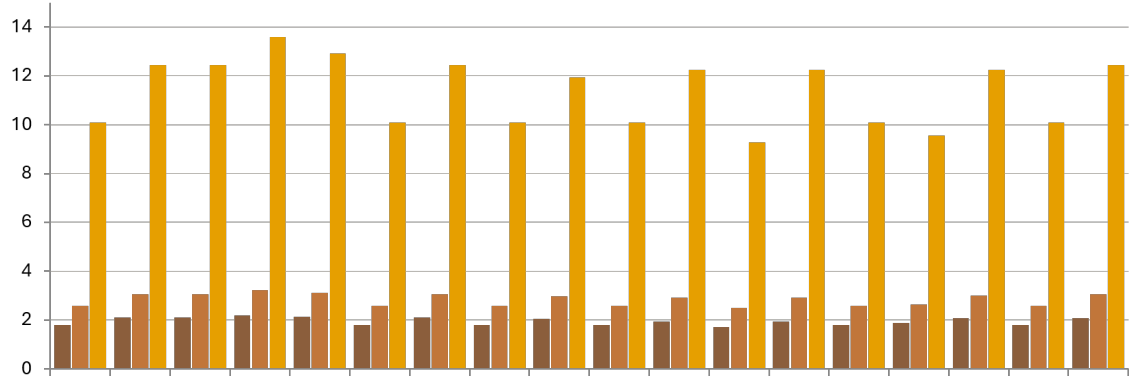
Electricity assumptions rely on weighted averages of balancing authority generation profiles; however, projects may address power needs through installations or contracts that more easily reduce CI, like on-site production (behind the meter), power purchasing agreements (PPAs), or renewable energy certificates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

Additional Results: PADD Region Variations

East Coast

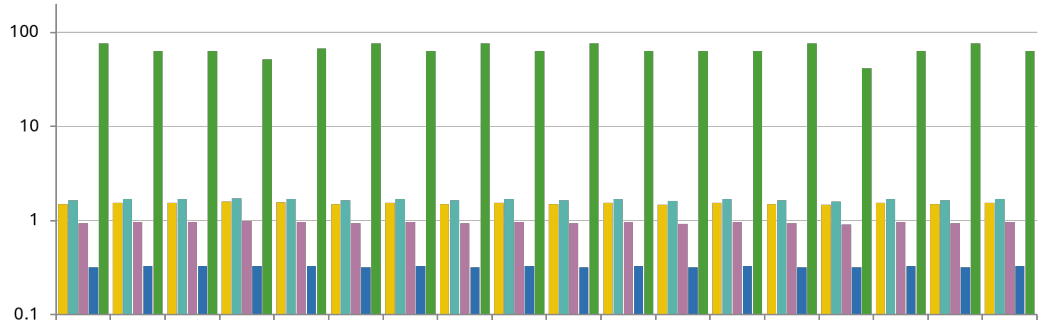
Overall, the East Coast produced the most favorable LCA results, with the exception of PEM electrolysis using hydro and biomass. Variation among states is moderate for most pathways, except for PEM with hydro, which remains consistently

between 0.32 and 0.33 kg CO_2e/kg H_2. Within the region, New York recorded the lowest emissions for the natural-gas-feedstock pathways, at 1.72, 2.48, and 9.27 kg CO_2e/kg H_2 for SMR with CCS, ATR with CCS, and pyrolysis, respectively, while South Carolina recorded the lowest emissions for solar-, wind-, and nuclear-powered PEM electrolysis, at 1.46, 1.59, and 0.91 kg CO_2e/kg H_2, respectively. Figure 15, Figure 16, and Figure 17 present the state-level emissions results for the East Coast for hydrogen and RNG.



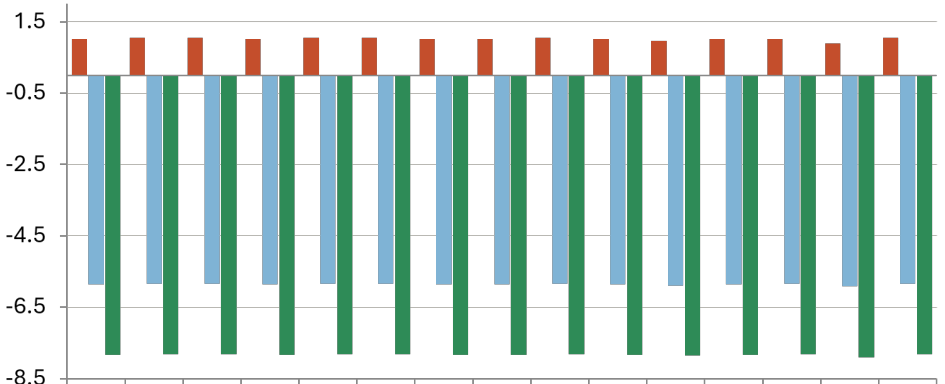
	CT	DC	DE	FL	GA	MA	MD	ME	NC	NH	NJ	NY	PA	RI	SC	VA	VT	WV
SMR + CCS	1.79	2.09	2.09	2.18	2.12	1.79	2.09	1.79	2.05	1.79	1.94	1.72	1.94	1.79	1.87	2.07	1.79	2.08
ATR + CCS	2.59	3.04	3.04	3.21	3.11	2.59	3.04	2.59	2.97	2.59	2.91	2.48	2.91	2.59	2.62	3.01	2.59	3.04
Pyrolysis	10.1	12.4	12.4	13.6	12.9	10.1	12.4	10.1	11.9	10.1	12.3	9.27	12.3	10.1	9.56	12.2	10.1	12.4

Figure 15. East Coast Hydrogen Production Emission Intensity by State in kg CO_2e/kg H_2 (Natural Gas Pathways)



	CT	DC	DE	FL	GA	MA	MD	ME	NC	NH	NJ	NY	PA	RI	SC	VA	VT	WV
PEM Solar	1.49	1.55	1.55	1.58	1.57	1.49	1.55	1.49	1.55	1.49	1.55	1.48	1.55	1.49	1.46	1.55	1.49	1.55
PEM Wind	1.63	1.68	1.68	1.71	1.7	1.63	1.68	1.63	1.68	1.63	1.68	1.62	1.68	1.63	1.59	1.68	1.63	1.68
PEM Nuclear	0.93	0.96	0.96	0.99	0.97	0.93	0.96	0.93	0.96	0.93	0.96	0.92	0.96	0.93	0.91	0.96	0.93	0.96
PEM Hydro	0.32	0.33	0.33	0.33	0.33	0.32	0.33	0.32	0.33	0.32	0.33	0.32	0.33	0.32	0.32	0.33	0.32	0.33
PEM Biomass	76.5	62.7	62.7	51.4	67.7	76.5	62.7	76.5	62.7	76.5	62.7	62.8	62.7	76.5	41.7	62.7	76.5	62.7

Figure 16. East Coast Hydrogen Production Emission Intensity by State in kg $CO_2e/kg\ H_2$ (Electrolysis Pathways)

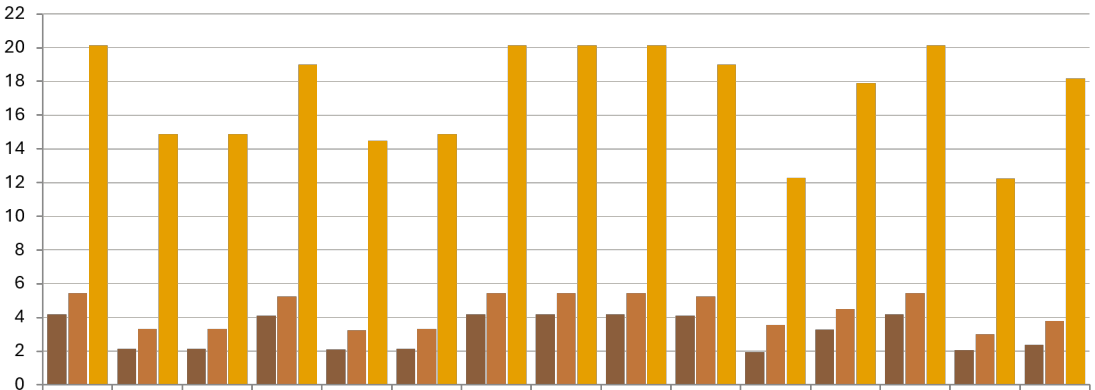


	IA	IL	IN	KS	KY	MI	MN	MO	ND	NE	OH	OK	SD	TN	WI
RNG-4 · Landfill Gas	1.02	1.06	1.06	1.02	1.06	1.06	1.02	1.02	1.06	1.02	0.97	1.02	1.02	0.89	1.06
RNG-5 · Wastewater	-5.86	-5.84	-5.84	-5.86	-5.84	-5.84	-5.86	-5.86	-5.84	-5.86	-5.89	-5.86	-5.84	-5.92	-5.84
RNG-6 · Animal Manure	-7.84	-7.82	-7.82	-7.84	-7.82	-7.82	-7.84	-7.84	-7.82	-7.84	-7.86	-7.84	-7.82	-7.9	-7.82

Figure 17. East Coast RNG Production Emission Intensity by State in kg CO_2e/kg

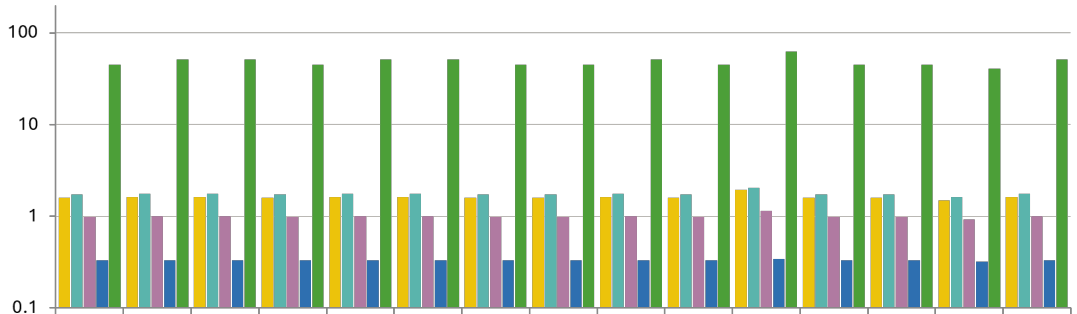
Midwest

As in the East Coast, variation among states is moderate for most pathways, except for PEM with hydro, which remains consistently between 0.33 and 0.34 kg CO_2e/kg H_2. Ohio has the lowest emissions for SMR with CCS (1.96 kg CO_2e/kg H_2), while Tennessee has the lowest emissions for the remaining pathways for both hydrogen and RNG this is attributable to the lower delivered-electricity emission intensity of the Tennessee Valley Authority relative to the MISO and SPP. Figure 18, Figure 19, and Figure 20 present the state-level emissions results for the Midwest for hydrogen and RNG.



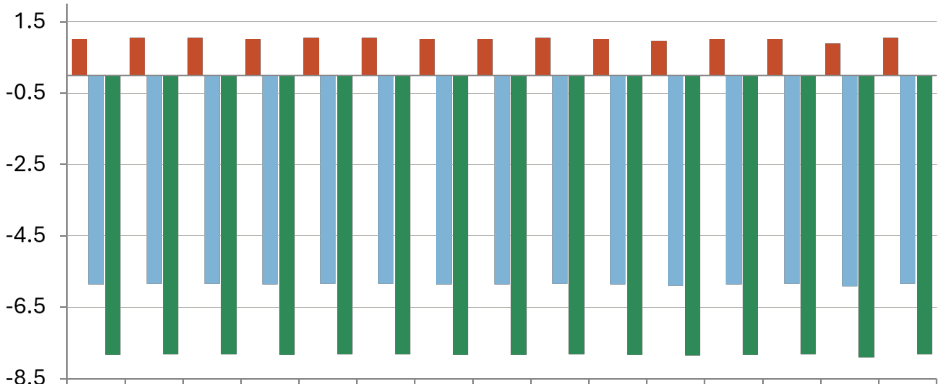
	IA	IL	IN	KS	KY	MI	MN	MO	ND	NE	OH	OK	SD	TN	WI
SMR + CCS	4.17	2.16	2.16	4.09	2.12	2.16	4.17	4.17	4.17	4.09	1.96	3.27	4.17	2.07	2.39
ATR + CCS	5.43	3.31	3.31	5.26	3.26	3.31	5.43	5.43	5.43	5.26	3.55	4.5	5.43	3.01	3.79
Pyrolysis	20.15	14.89	14.89	19.02	14.5	14.89	20.15	20.15	20.15	19.02	12.28	17.91	20.15	12.24	18.17

Figure 18. Midwest Hydrogen Production Emission Intensity by State in kg CO_2e/kg H_2 (Natural Gas Pathways)



	IA	IL	IN	KS	KY	MI	MN	MO	ND	NE	OH	OK	SD	TN	WI
PEM Solar	1.6	1.63	1.63	1.6	1.63	1.63	1.6	1.6	1.63	1.6	1.93	1.6	1.6	1.49	1.63
PEM Wind	1.73	1.76	1.76	1.73	1.76	1.76	1.73	1.73	1.76	1.73	2.03	1.73	1.73	1.63	1.76
PEM Nuclear	0.98	1.01	1.01	0.98	1.01	1.01	0.98	0.98	1.01	0.98	1.15	0.98	0.98	0.93	1.01
PEM Hydro	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.33	0.33	0.32	0.33
PEM Biomass	44.77	51.29	51.29	44.77	51.29	51.29	44.77	44.77	51.29	44.77	62.74	44.77	44.77	40.59	51.29

Figure 19. Midwest Hydrogen Production Emission Intensity by State in kg CO_2e/kg H_2 (Electrolysis Pathways)

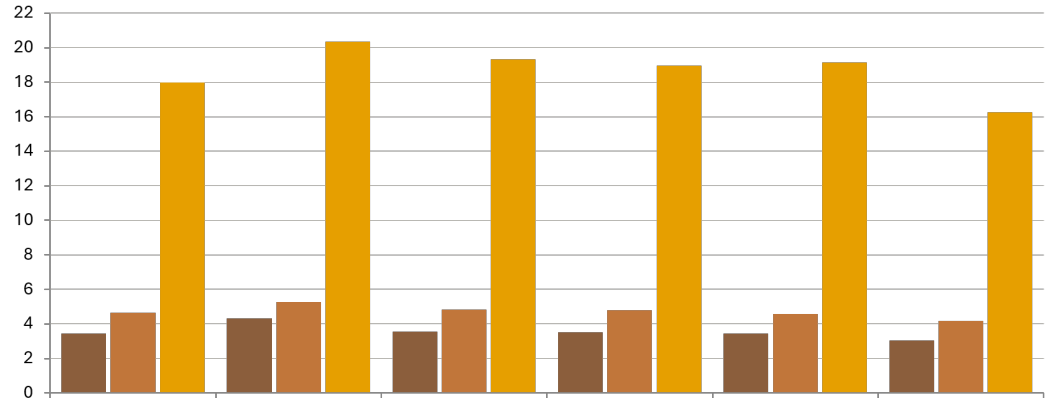


	IA	IL	IN	KS	KY	MI	MN	MO	ND	NE	OH	OK	SD	TN	WI
RNG-4 · Landfill Gas	1.02	1.06	1.06	1.02	1.06	1.06	1.02	1.02	1.06	1.02	0.97	1.02	1.02	0.89	1.06
RNG-5 · Wastewater	-5.86	-5.84	-5.84	-5.86	-5.84	-5.84	-5.86	-5.86	-5.84	-5.86	-5.89	-5.86	-5.84	-5.92	-5.84
RNG-6 · Animal Manure	-7.84	-7.82	-7.82	-7.84	-7.82	-7.82	-7.84	-7.84	-7.82	-7.84	-7.86	-7.84	-7.82	-7.9	-7.82

Figure 20. Midwest RNG Production Emission Intensity by State in kg CO_2e/kg

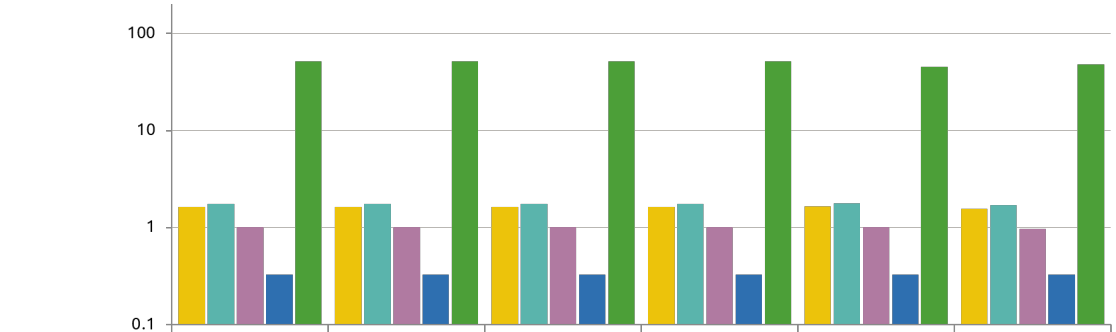
Gulf Coast

The Gulf Coast is effectively the middle ground across all pathways, ranking neither highest nor lowest in emissions. Cradle-to-gate emissions for PEM with hydro are consistent throughout the region at 0.33 kg CO_2e/kg H_2. There is meaningful variation across the region for the natural-gas-feedstock hydrogen pathways (SMR with CCS, ATR with CCS, and pyrolysis) and for the wastewater and animal-manure RNG pathways; however, Alabama, Arkansas, Louisiana, and Mississippi share identical cradle-to-gate emissions for the PEM pathways and the landfill-gas RNG pathway. Texas consistently recorded the lowest emissions for every pathway in the region except PEM with biomass, for which New Mexico is lowest. Figure 21, Figure 22, and Figure 23 present the state-level emissions results for the Gulf Coast for hydrogen and RNG.



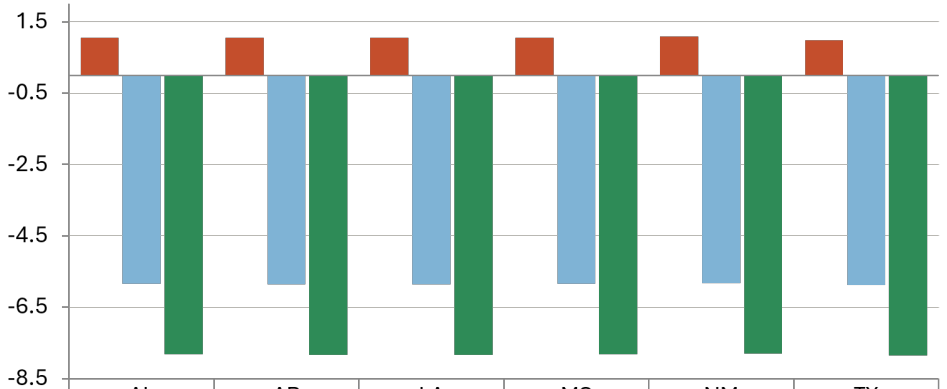
	AL	AR	LA	MS	NM	TX
SMR + CCS	3.46	4.32	3.55	3.53	3.44	3.04
ATR + CCS	4.65	5.26	4.84	4.79	4.58	4.17
Pyrolysis	17.99	20.35	19.31	18.95	19.13	16.27

Figure 21. Gulf Coast Hydrogen Production Emission Intensity by State in kg CO_2e/kg H_2 (Natural Gas Pathways)



	AL	AR	LA	MS	NM	TX
PEM Solar	1.63	1.63	1.63	1.63	1.66	1.57
PEM Wind	1.76	1.76	1.76	1.76	1.78	1.7
PEM Nuclear	1.01	1.01	1.01	1.01	1.01	0.97
PEM Hydro	0.33	0.33	0.33	0.33	0.33	0.33
PEM Biomass	51.29	51.29	51.29	51.29	44.98	47.97

Figure 22. Gulf Coast Hydrogen Production Emission Intensity by State in kg CO_2e/kg H_2 (Electrolysis Pathways)

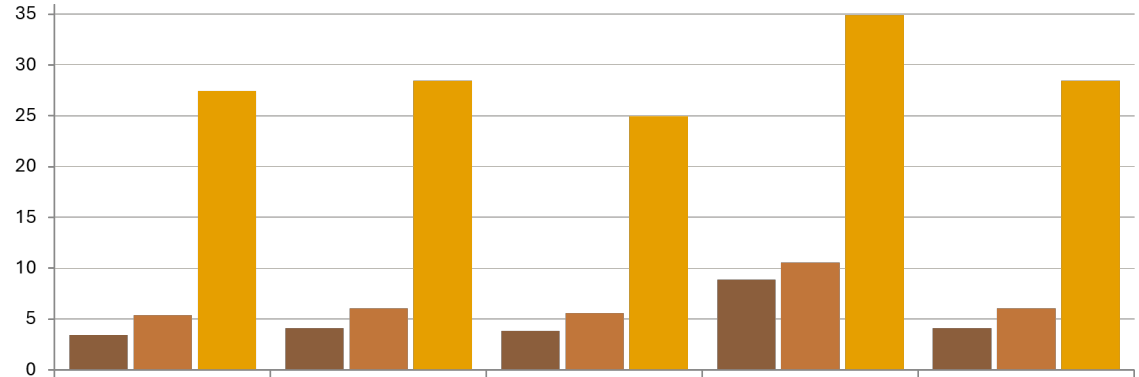


	AL	AR	LA	MS	NM	TX
RNG-4 · Landfill Gas	1.06	1.06	1.06	1.06	1.08	0.99
RNG-5 · Wastewater	-5.84	-5.86	-5.86	-5.84	-5.83	-5.87
RNG-6 · Animal Manure	-7.82	-7.84	-7.84	-7.82	-7.8	-7.85

Figure 23. Gulf Coast RNG Production Emission Intensity by State in kg CO_2e/kg

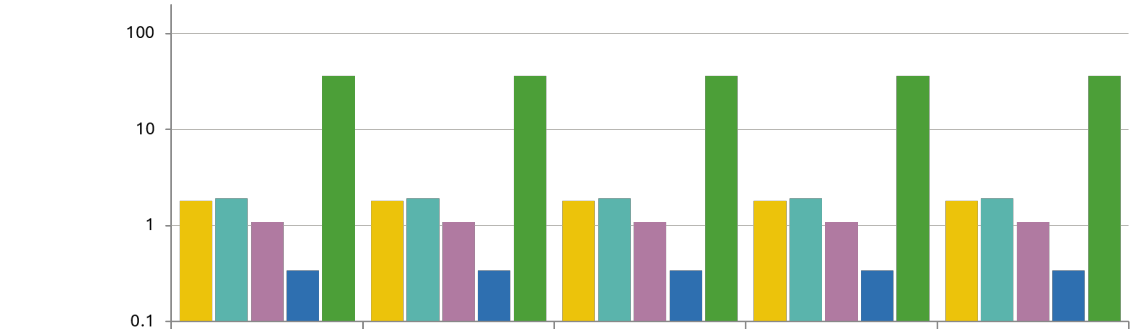
Rocky Mountain

In the Rocky Mountain region, variation between state is concentrated in the natural-gas-feedstock hydrogen pathways (SMR with CCS, ATR with CCS, and pyrolysis), for which Colorado has the lowest cradle-to-gate emissions in the region (3.4, 5.39, and 27.45 kg $CO_2e/kg\ H_2$ respectively). The remaining hydrogen and RNG pathways exhibit similar emissions across the region. Figure 24, Figure 25, and Figure 26 present the state-level emissions results for the Rocky Mountain region for hydrogen and RNG.



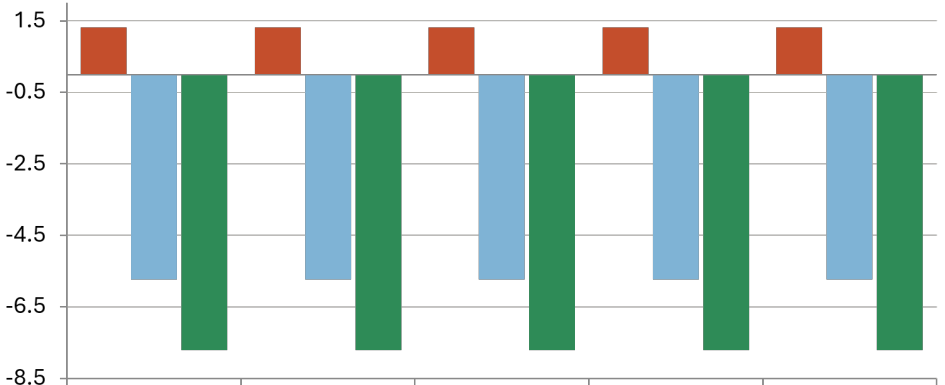
	CO	ID	MT	UT	WY
SMR + CCS	3.4	4.11	3.85	8.9	4.11
ATR + CCS	5.39	6.06	5.55	10.56	6.06
Pyrolysis	27.45	28.42	24.93	34.92	28.42

Figure 24. Rocky Mountain Hydrogen Production Emission Intensity by State in kg $CO_2e/kg\ H_2$ (Natural Gas Pathways)



	CO	ID	MT	UT	WY
PEM Solar	1.81	1.81	1.81	1.81	1.81
PEM Wind	1.92	1.92	1.92	1.92	1.92
PEM Nuclear	1.09	1.09	1.09	1.09	1.09
PEM Hydro	0.34	0.34	0.34	0.34	0.34
PEM Biomass	36.27	36.27	36.27	36.27	36.27

Figure 25. Rocky Mountain Hydrogen Production Emission Intensity by State in kg CO_2e/kg H_2 (Electrolysis Pathways)

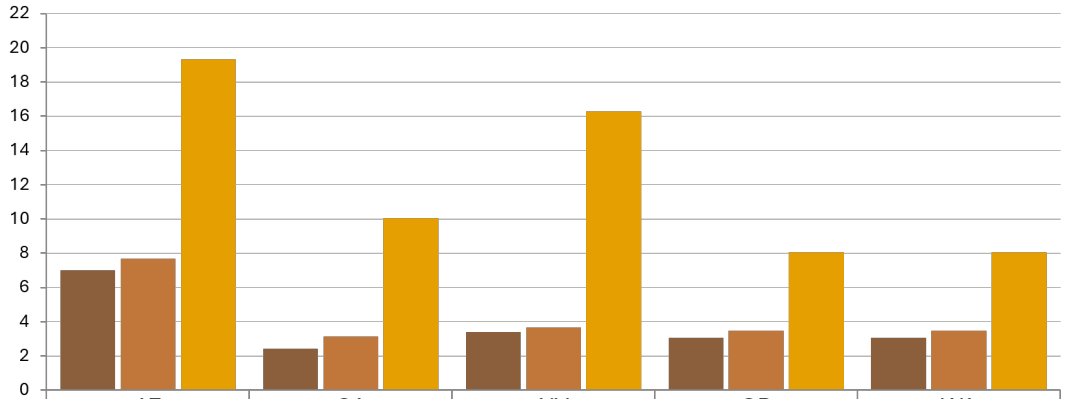


	CO	ID	MT	UT	WY
RNG-4 · Landfill Gas	1.31	1.31	1.31	1.31	1.31
RNG-5 · Wastewater	-5.73	-5.73	-5.73	-5.73	-5.73
RNG-6 · Animal Manure	-7.72	-7.72	-7.72	-7.72	-7.72

Figure 26. Rocky Mountain RNG Production Emission Intensity by State in kg CO_2e/kg

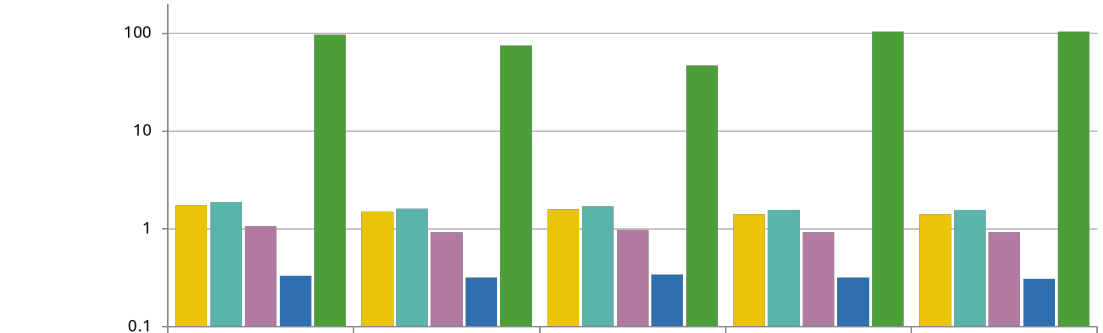
West Coast

The West Coast exhibits considerable variation between states because it spans nearly the full range of U.S. grid carbon intensities, from the hydro-dominated, near-zero-carbon grids of the Pacific Northwest to the more fossil-reliant Southwest. California has the lowest cradle-to-gate emissions for SMR with CCS and ATR with CCS, at 2.44 and 3.13 kg CO_2e/kg H_2, respectively. Oregon and Washington, in turn, lead on the electricity-intensive pathways (plasma pyrolysis and PEM with solar, wind, and nuclear) because their hydropower-based grids carry almost no carbon, with Washington lowest for PEM-hydro given its hydro abundance. Figure 27, Figure 28, and Figure 29 present the state-level emissions results for the West Coast for hydrogen and RNG.



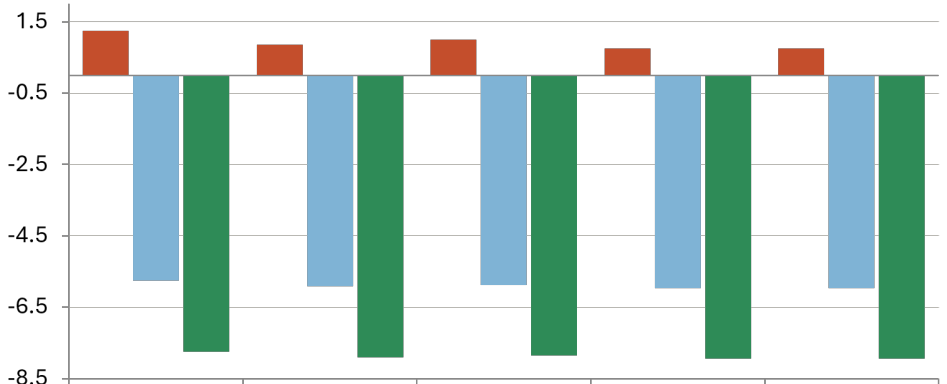
	AZ	CA	NV	OR	WA
SMR + CCS	6.99	2.44	3.39	3.06	3.06
ATR + CCS	7.68	3.13	3.67	3.47	3.47
Pyrolysis	19.31	10.04	16.27	8.06	8.06

Figure 27. West Coast Hydrogen Production Emission Intensity by State in kg CO_2e/kg H_2 (Natural Gas Pathways)



	AZ	CA	NV	OR	WA
PEM Solar	1.76	1.49	1.58	1.42	1.42
PEM Wind	1.87	1.62	1.71	1.56	1.56
PEM Nuclear	1.07	0.92	0.98	0.92	0.92
PEM Hydro	0.33	0.32	0.34	0.32	0.31
PEM Biomass	96.35	74.59	47.01	104.35	104.35

Figure 28. West Coast Hydrogen Production Emission Intensity by State in kg CO_2e/kg H_2 (Electrolysis Pathways)



	AZ	CA	NV	OR	WA
RNG-4 · Landfill Gas	1.25	0.86	1	0.76	0.76
RNG-5 · Wastewater	-5.76	-5.92	-5.87	-5.96	-5.96
RNG-6 · Animal Manure	-7.75	-7.9	-7.85	-7.94	-7.94

Figure 29. West Coast RNG Production Emission Intensity by State in kg CO_2e/kg

Appendix F: National Policy Landscape Assessment

Rating Justification for the Cross-Regional Policy Alignment Matrix

Purpose and methodology

This appendix documents the basis for the ratings in the Cross-Regional Policy Alignment Matrix. The matrix compares the five regions based on the degree to which their policy objectives and general approaches align across the study's 15 policy subtopics.

Ratings are qualitative and do not reflect the number of policy records, the number of states represented, or the overall level of policy activity. For each subtopic, the analysis compared the intended outcomes, underlying policy rationale, and principal mechanisms.

Rating scale

- **High:** Regions are consistently aligned in policy objectives and general approach; differences primarily concern implementation details.
- **Moderate-High:** Regions share similar objectives and broadly comparable approaches, with meaningful differences in rationale or implementation.
- **Moderate:** Regions recognize a similar policy need but use materially different strategies, priorities, or policy mechanisms.
- **Low-Moderate:** Some common objectives exist, but regional approaches are substantially different or only partly comparable.
- **Low:** Regions pursue fundamentally different policy directions or rely on conflicting underlying assumptions.

Natural Gas Industry and Infrastructure

Natural Gas Outlook: Low

The regions differ fundamentally on the desired long-term role of natural gas. Transition-oriented policies in parts of the East Coast, Midwest, Rocky Mountain, and West Coast evaluate electrification, non-gas alternatives, emissions reductions, and reduced utility incentives for system expansion. Other policies across the Gulf Coast, Midwest, Rocky Mountain, and portions of the East and West Coast preserve fuel choice, facilitate infrastructure access, support natural-gas development, or prioritize continued

use of gas for affordability and reliability. These are competing policy objectives rather than variations in implementation, supporting a Low rating.

Infrastructure Maintenance and Modernization: High

All five regions consistently prioritize the safe and reliable operation of existing natural-gas infrastructure. Common approaches include pipeline-safety standards, inspections, integrity management, leak detection and repair, system replacement, enforcement, and regulatory review of modernization investments. Regions differ in cost recovery, emissions treatment, investment review, and the relationship between modernization and long-term gas planning, but these differences do not alter the shared safety and integrity objective.

Natural Gas Storage: Moderate-High

Where natural gas storage is addressed, regional policies generally emphasize safe operation, well and reservoir integrity, permitting, regulatory oversight, supply continuity, and peak-demand reliability. Differences concern storage's broader strategic role: some policies primarily regulate conventional storage operations, while others explicitly connect storage with electric generation, emergency planning, gas-electric coordination, or evaluation of long-term system needs. These approaches are broadly compatible but not uniform, supporting a Moderate-High rating.

Emerging Fuels and Decarbonization Pathways

Renewable Natural Gas: Moderate

Regions generally treat RNG as a lower-carbon fuel or an alternative that can use portions of the existing gas system. Their policy approaches differ across utility procurement, innovation plans, pipeline interconnection and gathering-line rules, clean-fuel standards, tax incentives, project funding, transportation uses, voluntary customer offerings, and emissions-reduction planning. The common enabling objective prevents a lower rating, but differences in the intended role of RNG and the mechanisms used to support it limit alignment to Moderate.

Hydrogen: Moderate

All regions recognize hydrogen as a potential energy, industrial, transportation, storage, or decarbonization pathway. However, the datasets show materially different objectives involving industrial development, heavy transportation, utility-system integration, renewable-energy storage, pipeline use, underground storage, regional hubs, and

economic development. Regions also differ in preferred production pathways and in their reliance on roadmaps, studies, incentives, utility authority, infrastructure regulation, or direct project support. The shared interest is clear, but the approaches are not sufficiently comparable for Moderate-High.

Carbon Capture, Utilization, and Storage: Moderate

The regions generally recognize a need for permitting, transport oversight, geologic-storage regulation, monitoring, financial assurance, or long-term stewardship. Policy purposes nevertheless differ substantially, including industrial decarbonization, continued operation of fossil generation, hydrogen production, economic development, enhanced oil recovery, direct-air-capture innovation, and compliance with power-sector requirements. Land-use treatment, project restrictions, pore-space rules, financing, and acceptable applications also differ, supporting a Moderate rating despite common governance needs.

Renewables: Low-Moderate

Renewable and clean energy policy is present across all regions, but the underlying objectives and approaches differ substantially. Coastal regions and selected states elsewhere use binding renewable, clean-electricity, emissions-reduction, procurement, and transition requirements. Other jurisdictions rely on voluntary goals, tax incentives, customer programs, technology-neutral portfolios, advanced-nuclear development, or broader strategies that preserve conventional and dispatchable generation. The datasets' Renewables classification also includes some nuclear, efficiency, storage, and alternative-energy measures, increasing the diversity of approaches captured by this subtopic.

Reliability, Resilience, and System Planning

Grid Reliability and Resilience: High

All five regions consistently prioritize reliable service, resource adequacy, emergency preparedness, infrastructure protection, and recovery from system disruptions. Policies address different regional risks, including wildfire, extreme heat, winter weather, hurricanes, storms, seismic hazards, fuel disruptions, and infrastructure constraints, but they use broadly comparable approaches such as preparedness standards, utility plans, hazard assessments, system hardening, emergency procedures, and regulatory oversight. The specific risks vary, while the core objectives remain closely aligned.

Evaluation and Valuation: Moderate

All regions use utility planning, commission review, energy-security assessments, resource planning, or similar processes to evaluate costs, demand, reliability, risks, and system needs. The criteria applied in those evaluations differ materially, however. Some policies emphasize emissions, social costs, electrification, equity, and alternatives to conventional infrastructure, while others place greater weight on affordability, dispatchability, fuel security, economic development, or preservation of existing generation. These differences can lead to different investment decisions even where the regulatory process is similar.

Demand Surge Reality: Moderate-High

Regions generally address projected demand, peak conditions, large-load or industrial growth, extreme-weather stress, and resource adequacy through load forecasting, seasonal assessments, integrated resource planning, capacity demonstrations, demand response, curtailment plans, and generation or transmission review. The principal demand drivers and preferred responses vary, but the shared objective is to anticipate material changes in demand and ensure sufficient system capability. This broad similarity in planning approach supports a Moderate-High rating.

Infrastructure Design and Storage: Moderate

All regions evaluate infrastructure capacity, flexibility, and storage as part of future system planning, but they emphasize different asset types and solutions. Regional policies variously prioritize transmission, distribution, gas capacity, generation, battery storage, conventional fuel storage, microgrids, hydrogen infrastructure, carbon storage, distributed resources, and non-wires alternatives. The common concern is adequate and adaptable infrastructure, but the preferred designs and technologies differ materially.

Gas-Electric Coordination: Moderate

The regions recognize that electric reliability can depend on natural-gas supply, storage, delivery, and emergency operations. Approaches include integrated gas-electric planning, critical-infrastructure mapping, energy-security plans, emergency curtailment priorities, interagency coordination, storage support for generation, and parallel utility-resource planning. These measures address a similar cross-system concern, but the degree of formal integration and the institutions responsible for coordination vary considerably.

Workforce Development

Transition and Retention: Moderate

Transition and retention policies generally seek to reduce disruption for workers, employers, and communities affected by facility closures, decarbonization, changing technologies, or broader economic shifts. Regional approaches include worker protections, just-transition offices, community grants, retraining, incumbent-worker programs, economic-diversification assistance, and workforce advisory structures. The general objective is shared, but the triggering conditions, eligible populations, and degree of direct assistance differ.

Emerging Skills Gap: Moderate-High

All regions support development of skills associated with evolving energy technologies and infrastructure. Common approaches include workforce studies, training grants, apprenticeships, employer partnerships, higher-education programs, technology-specific curricula, and advisory bodies. Regional priorities differ across hydrogen, CCUS, renewable energy, advanced nuclear, electrification, grid modernization, pipeline work, and advanced manufacturing, but the objective and general training approach are broadly comparable.

Capacity Constraints: Moderate-High

Regions generally seek to expand the workforce available for energy development and implementation through apprenticeships, scholarships, internships, employer-led training, education partnerships, workforce grants, and career-pathway programs. Differences concern whether programs are energy-specific or economy-wide, mandatory or voluntary, employer-led or state-administered, and directly connected to planned deployment. The common workforce-expansion objective and recurring use of similar delivery mechanisms support a Moderate-High rating rather than High.

Rating Justification for Relative Policy Support for Emerging Fuels and Decarbonization Pathways

Purpose and methodology

This appendix documents the basis for each rating in the **Relative Policy Support for Emerging Fuels and Decarbonization Pathways Matrix**. Ratings reflect the diversity,

directness, and complementarity of the policy support represented in the five regional datasets, not the number of policy records.

Rating scale

- **High:** Comprehensive and direct support through multiple complementary mechanisms, such as mandates, regulatory frameworks, incentives, infrastructure provisions, programs, and implementation planning.
- **Moderate-High:** Strong support through several substantive mechanisms, with some gaps in scope, integration, implementation, or consistency within the region.
- **Moderate:** Established support is present through multiple mechanisms, but the approaches are targeted, uneven, or primarily enabling rather than comprehensive.
- **Low-Moderate:** Support is limited to a narrower range of targeted incentives, programs, studies, definitions, pilots, or early enabling frameworks.
- **Low:** Little direct support is evident; policies are largely exploratory, indirect, restrictive, or not linked to an established implementation mechanism.

Renewable Natural Gas

East Coast: Moderate

East Coast RNG policy includes utility procurement and cost-recovery authority in New Hampshire, equipment tax incentives in Florida and South Carolina, project funding in North Carolina, and consideration of RNG within Rhode Island's thermal-sector planning. These measures provide established support through several mechanisms, but they do not form an integrated regional framework for procurement, infrastructure access, utility programs, and market development.

Midwest: Moderate-High

Midwest policies support RNG through utility innovation and investment authority, infrastructure financing, gathering line and interconnection requirements, regulatory cost treatment, pilots, and voluntary customer programs. The mechanisms are diverse and address both infrastructure and utility participation, but they remain uneven and less fully integrated than the West Coast framework.

Gulf Coast: Low-Moderate

Gulf Coast support is primarily enabling and concentrated in New Mexico's clean transportation fuel standard and alternative-fuel framework. These policies can recognize or provide market value for lower-carbon fuels, but the dataset does not show a broader regional framework covering RNG procurement, interconnection, utility investment, financing, and deployment.

Rocky Mountain: Low-Moderate

Rocky Mountain policies support RNG through Colorado clean-heat planning, a Utah utility transportation tariff, Montana tax treatment, and Wyoming project funding. These measures provide direct but narrow support and are generally embedded in broader policies or individual projects rather than a comprehensive RNG framework.

West Coast: High

West Coast policies combine utility procurement, pipeline-interconnection standards, project incentives, clean-fuel standards, utility investment and cost recovery, and voluntary customer offerings. California, Oregon, Nevada, and Washington collectively address production, infrastructure access, utility participation, and market development, supporting a High rating.

Hydrogen

East Coast: Moderate-High

East Coast hydrogen policy includes state planning, roadmaps, tax credits, innovation funding, infrastructure studies, planning grants, regional hub participation, and workforce support. These mechanisms provide strong strategic and project-development support, but much of the activity remains focused on planning and early implementation rather than an integrated production, infrastructure, and market framework.

Midwest: High

Midwest policies support hydrogen through production goals, tax incentives, pipeline regulation, utility innovation authority, infrastructure planning, regional hubs, industrial and agricultural applications, and workforce development. Together, these mechanisms address production, transport, storage, utility participation, end uses, and regional market development.

Gulf Coast: High

Gulf Coast policies combine hydrogen-production governance, infrastructure and equipment grants, underground-storage authority, transportation applications, alternative-fuel treatment, hub development, and workforce programming. The collected policies directly support several parts of the hydrogen value chain and connect hydrogen with existing industrial and energy infrastructure.

Rocky Mountain: Moderate-High

Rocky Mountain support includes roadmaps, transportation and storage studies, regulatory authority, advisory bodies, grant eligibility, siting provisions, and tax treatment. These are substantive mechanisms, but the regional framework remains weighted toward planning and governance rather than direct procurement, infrastructure deployment, and market implementation.

West Coast: Moderate-High

West Coast policies support hydrogen through utility investment authority, clean-fuel standards, planning studies, pilot testing, regional strategies, clean-energy funding, and workforce analysis. Support is strongest in California and Washington, while other states rely more heavily on studies and enabling authority, creating gaps in implementation across the region.

Carbon Capture, Utilization, and Storage

East Coast: Moderate-High

East Coast CCUS support includes Pennsylvania's permitting, pore-space, liability, and post-closure framework; West Virginia's Class VI authority and hub-related storage activity; and Virginia innovation funding. These policies provide consequential regulatory and project support, but they are less diversified and integrated than the frameworks found in the High-rated regions.

Midwest: High

Midwest policies address carbon capture, pipeline siting and safety, geologic storage, pore-space ownership, Class VI administration, tax incentives, bond financing, demonstration projects, and long-term oversight. The combination of regulatory, financial, infrastructure, and project-development mechanisms supports a High rating.

Gulf Coast: High

Gulf Coast policies provide extensive support for capture, transport, injection, and storage through permitting frameworks, pipeline authority, pore-space provisions, Class VI administration, trust funds, tax incentives, closure requirements, and long-term stewardship. These mechanisms directly support both project development and continuing state oversight.

Rocky Mountain: High

Rocky Mountain policies combine geologic storage permitting, pore-space ownership, liability provisions, Class VI authority, storage funds, capture-readiness requirements, project financing, and state carbon management planning. The framework addresses the principal governance and implementation needs associated with carbon capture, transport, and storage.

West Coast: Moderate-High

West Coast support includes Class VI administration, geologic storage and pipeline regulation, interagency permitting, implementation programs, carbon-removal funding, and power-sector requirements. The mechanisms are substantive, but state objectives and accepted applications differ, including California's prohibition on using captured carbon dioxide for enhanced oil recovery.

Renewables

East Coast: High

East Coast policies provide binding renewable and clean-energy standards, emissions requirements, offshore-wind targets, utility planning, procurement and interconnection provisions, project financing, distributed energy programs, and workforce support. These complementary mechanisms support renewable development, system integration, implementation, and associated workforce needs.

Midwest: Moderate-High

Midwest support includes renewable and carbon-free energy standards, tax incentives, siting frameworks, portfolio programs, net-metering provisions, utility planning, and clean energy programs. These mechanisms are diverse and established, but state approaches range from binding transitions to voluntary or technology-neutral strategies, limiting regional consistency.

Gulf Coast: Moderate

Gulf Coast renewable support includes New Mexico's cleanenergy requirements, community solar, clean-fuel and grid-modernization policies; Texas's renewable portfolio standard; Arkansas net-metering policy; and selected workforce and advanced-energy initiatives. The support is meaningful but uneven and does not form a common regional renewable-transition framework.

Rocky Mountain: Moderate

Rocky Mountain policies include Colorado renewable standards and clean-energy planning, Idaho and Utah tax incentives, customer renewable contracts, geothermal initiatives, project funding, and advanced-nuclear development. These supportive measures coexist with Montana's repeal of its renewable portfolio standard and broader regional emphasis on technology-neutral or dispatchable resources.

West Coast: High

West Coast policies combine binding renewable and clean-electricity standards, utility procurement and planning, transmission development, grants, tax incentives, community-energy programs, customer procurement options, clean-fuel standards, and workforce requirements. These tools provide comprehensive support from project development through grid integration and market participation.

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