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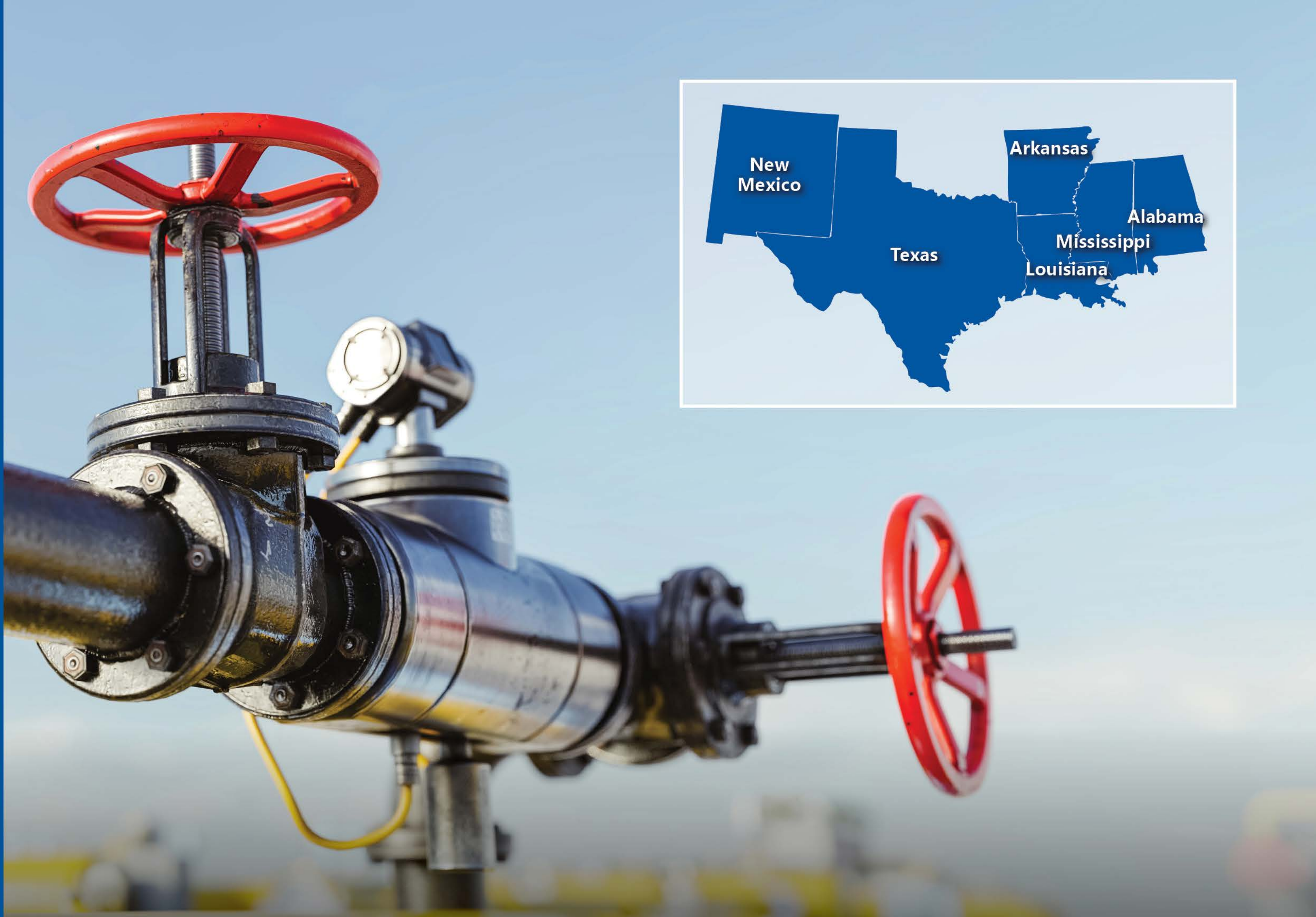
Reliable Affordable Infrastructure for Secure Energy



APPENDICES

Utilizing Gulf Coast Natural Gas Infrastructure for Emerging Fuels

AUGUST 2025

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Appendix A: Emerging Fuel Pathways Considered

Hydrogen

Hydrogen (H_2) is typically produced via steam methane reforming (SMR) of natural gas for 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, Case H2-1 represents H_2 production via SMR of natural gas incorporating carbon capture and storage (CCS) 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.

Case H2-2 is production via 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 (2025) 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). Costs are reflective of the selected process designs from Lewis, et al. (2022).

Case H2-3 represents SMR of RNG upgraded from landfill gas (LFG) sourced from the region, without CCS. Case H2-4 represents ATR of RNG without CCS. Case H2-5 represents SMR of RNG with CCS, with a configuration similar to case H2-1 in implementing a capture rate of over 96% (Lewis, et al., 2022). Case H2-6 represents ATR of RNG with CCS, with a configuration similar to case H2-2 in implementing a capture rate of over 94% (Lewis, et al., 2022).

Case H2-7 represents H_2 production via plasma pyrolysis of natural gas, in which a plasma torch is used to decompose methane (CH_4) 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.

Case H2-8 represents H_2 production via proton exchange membrane (PEM) electrolysis 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. Case H2-8 has been expanded to six sub-cases to evaluate production using six different low-carbon electricity sources: H2-8a uses electricity sourced from photovoltaic (PV) solar; H2-8b, onshore wind; H2-8c, nuclear power; H2-8d, hydropower; H2-8e, biomass without CCS; and case H2-8a/b combines solar and wind with battery storage to improve capacity factors (CFs) (EIA, 2022b).

Renewable Natural Gas

The RNG cases involve thermal or biological conversion of natural or waste resources into a natural gas alternative. 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 (EERE, n.d.); however, it will still create CO_2 emissions when combusted.

Case RNG-1 represents utilizing gasification technology to convert municipal solid waste (MSW) diverted from landfills into syngas, a mixture of carbon monoxide (CO) and H_2, which can then be upgraded to RNG via the methanation process.

Case RNG-2 represents RNG production from woody biomass (e.g., organic material derived from trees, shrubs, vines, leaves, etc.) via gasification and methanation processes. Case RNG-3 represents RNG production from herbaceous biomass (e.g., annual or perennial plants with soft, flexible stems such as grasses and grains) via gasification and methanation processes. Case RNG-4 represents RNG production by upgrading LFG produced through anaerobic digestion of MSW from landfills.

Synthetic Natural Gas

SNG is produced by converting CO_2 and H_2 into a natural gas alternative. This study only considers electrolysis-to-methanation pathways using CO_2 from industrial or power plants that sell captured CO_2 to offset capture costs, avoiding the need for CO_2 transport and storage. H_2 is produced via PEM electrolysis with low-carbon electricity, following the same specifications as case H2-8. Unlike low-carbon H_2, SNG can replace natural gas without retrofitting but still emits CO_2 when combusted (EERE, n.d.). SNG-1 represents utilizing CO_2 captured from the flue gas of a natural gas combined cycle (NGCC) power plant using a solvent-based capture system. For SNG-2, the CO_2 is captured from a cement plant, specifically from the kiln off-gas. SNG-3 sources CO_2 from a steel plant, including the power plant stack, coke oven gas, and the blast furnace stove. SNG-4 uses the high-purity CO_2 byproduct from fermentation at an ethanol plant, requiring only compression. Note that the availability of the CO_2 feedstock and, therefore, the ability to produce SNG, depends on the existence of the CO_2 point source facility type within the region. For the Gulf Coast region, for example, there are no steel plants that utilize blast furnaces to smelt iron ore; therefore, there are no cost results for Case SNG-3. Affordable access to CO_2 and H_2 must both be factored when producing SNG from these feedstocks. Since multiple cost scenarios exist for H2-8 based on the low-carbon electricity source, the two lowest-cost scenarios are used to supply H_2. Consequently, SNG cases include letters that denote the source of electricity used to produce electrolytic H_2 (e.g., “SNG-2c” signifies that the electrolytic H_2 is produced via nuclear electricity).

Appendix B: Case Study Approach

Optimization Model

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) (EIA, 2022c), Electricity Market Module (EMM) (EIA, 2022a), and Oil & Gas Supply Module (OGSM) (EIA, 2020) in OL-NEMS, the following discussion describes the regionality of the various data flows between them.

Regional Updates for H_2

The HMM uses census regions for fuel and electricity demand and H_2 supply. As seen in **Figure 1**, the PADD Gulf Coast regionality includes census regions six, seven, and eight. To determine the fuel and electricity demand for the PADD Gulf Coast region, the H_2 demand is restricted to census regions six, seven, and eight proportional to an assumed share of the states' demand. Thus, the total demand in the Gulf Coast region is the sum of New Mexico's share in census region eight, Texas, Arkansas, and Louisiana's share in census region seven, and Alabama and Mississippi's share in census region six.

The natural gas and electricity price inputs into the HMM are available at the census region level and do not change between states. Therefore, these prices are used for the PADD Gulf Coast region unchanged. Natural gas and electricity supply can be limited to be proportional to the states' share of the supply in census regions six, seven, and eight.

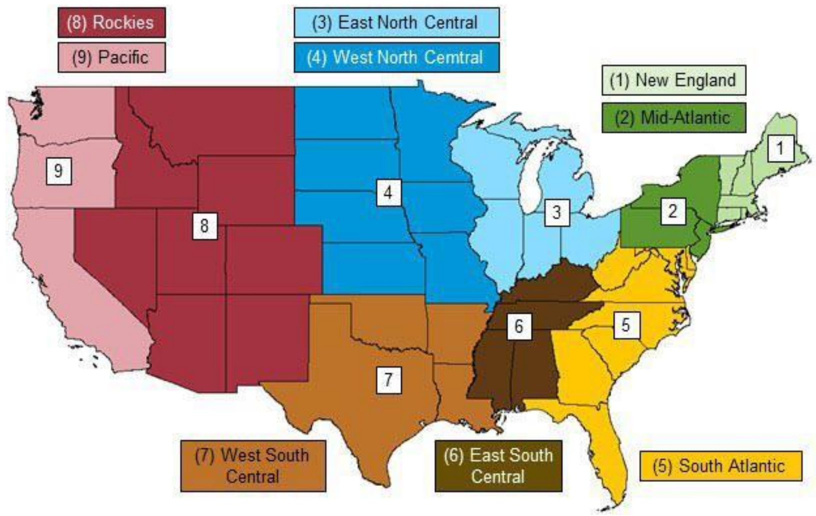

Figure 1. U.S. census regions, numbered (source: EIA)

Regional Reporting for Natural Gas

The natural gas price from the NGMM is provided by census region to the HMM and by EMM fuel region to the EMM. Nine census regions of the lower 48 states (**Figure 2**) are used to provide prices to the HMM. 23 subdivisions of census regions in the lower 48 states are used to provide more granular prices to the EMM (**Figure 3**).

Onshore natural gas production is reported by the OGSM at the OGSM region level. The PADD Gulf Coast region consists of the OGSM's Gulf Coast, Southwest, Midcontinent, and Rocky Mountain regions. The OGSM also reports district-level natural gas production, which can be used to calculate overall production in the PADD Gulf Coast region. New Mexico is reported as the East and West subregions and can be added to obtain the supply for New Mexico.

Texas is subdivided into 12 OGSM districts, which are reported separately as well and can be added together. Production in Arkansas is available for the state, while Louisiana, Alabama, and Mississippi are reported for North and South subregions and can be added together.

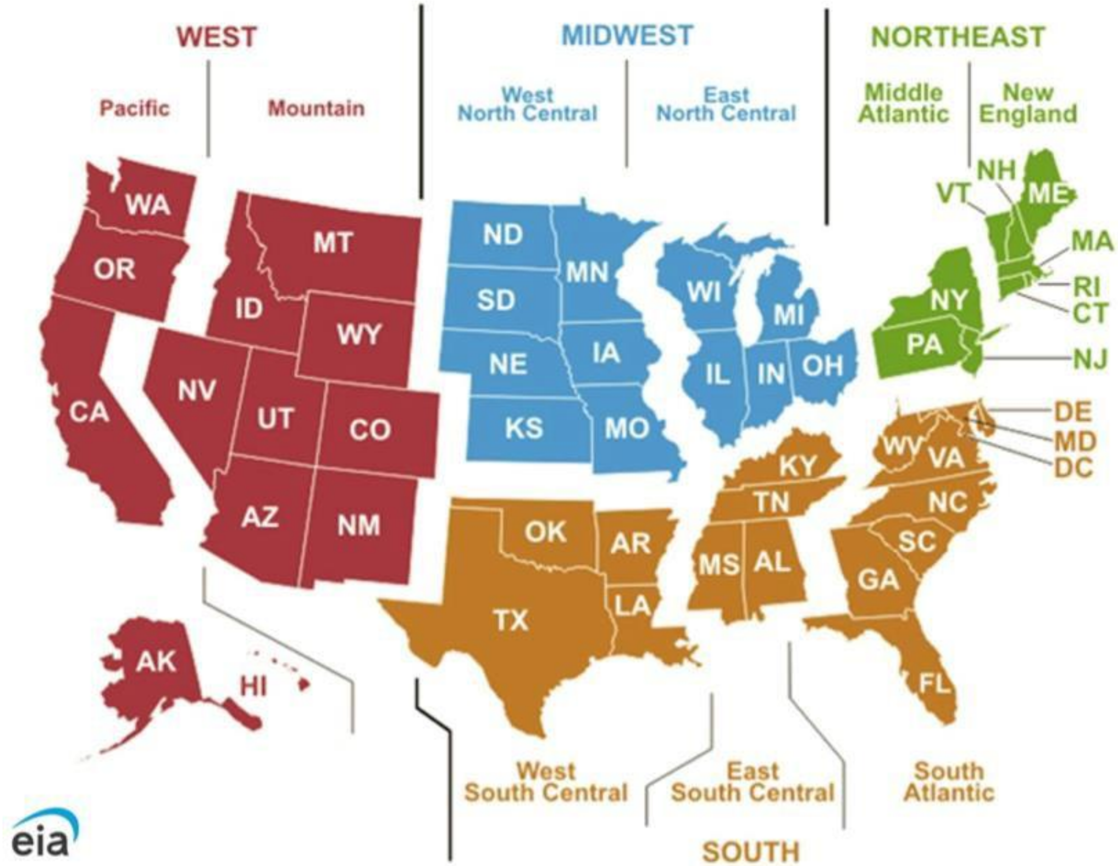

Figure 2. U.S. census regions (source: EIA)

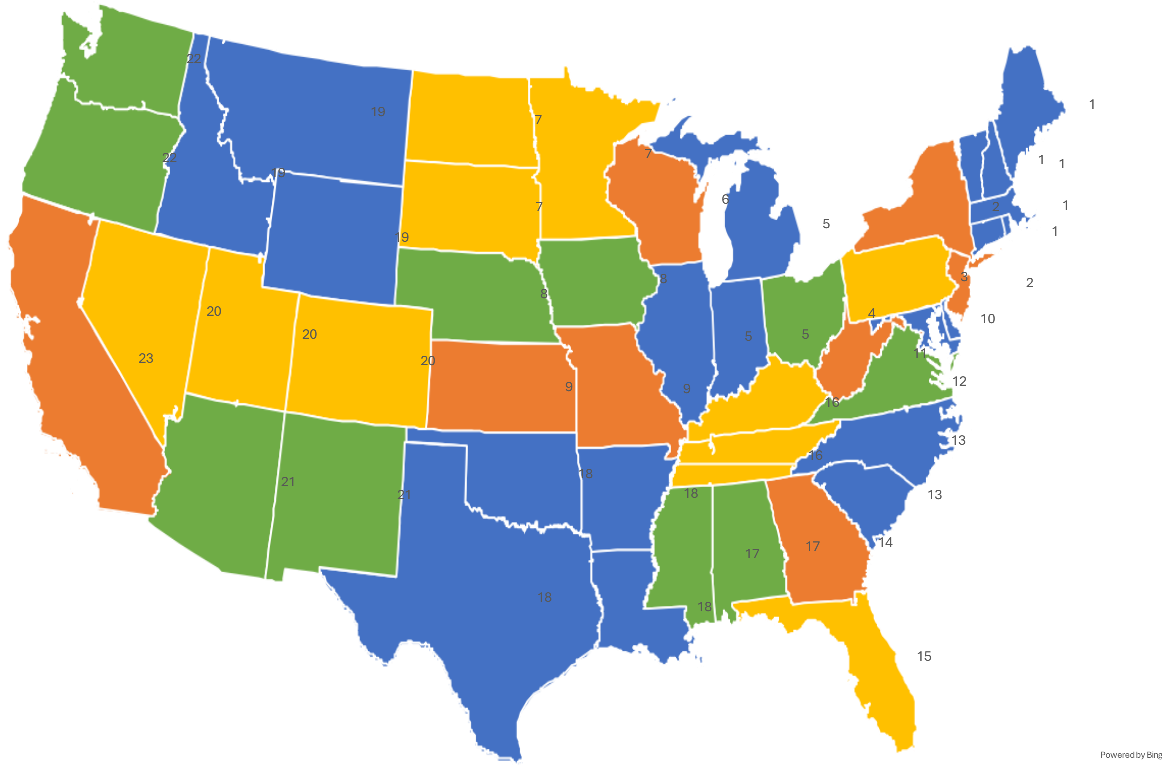

Figure 3. EMM fuel regions

Below are maps of the oil and gas supply regions and Texas's oil and gas districts for reference. Onshore natural gas production is reported by the OGSM at the OGSM region level as seen in **Figure 4**.

Texas is subdivided into 12 OGSM districts **(Figure 5**), which are reported separately as well and can be added together. Production in Arkansas is available for the state, while Louisiana, Alabama, and Mississippi are reported for North and South subregions and can be added together.

Figure 4. Oil and gas supply regions (source: EIA)

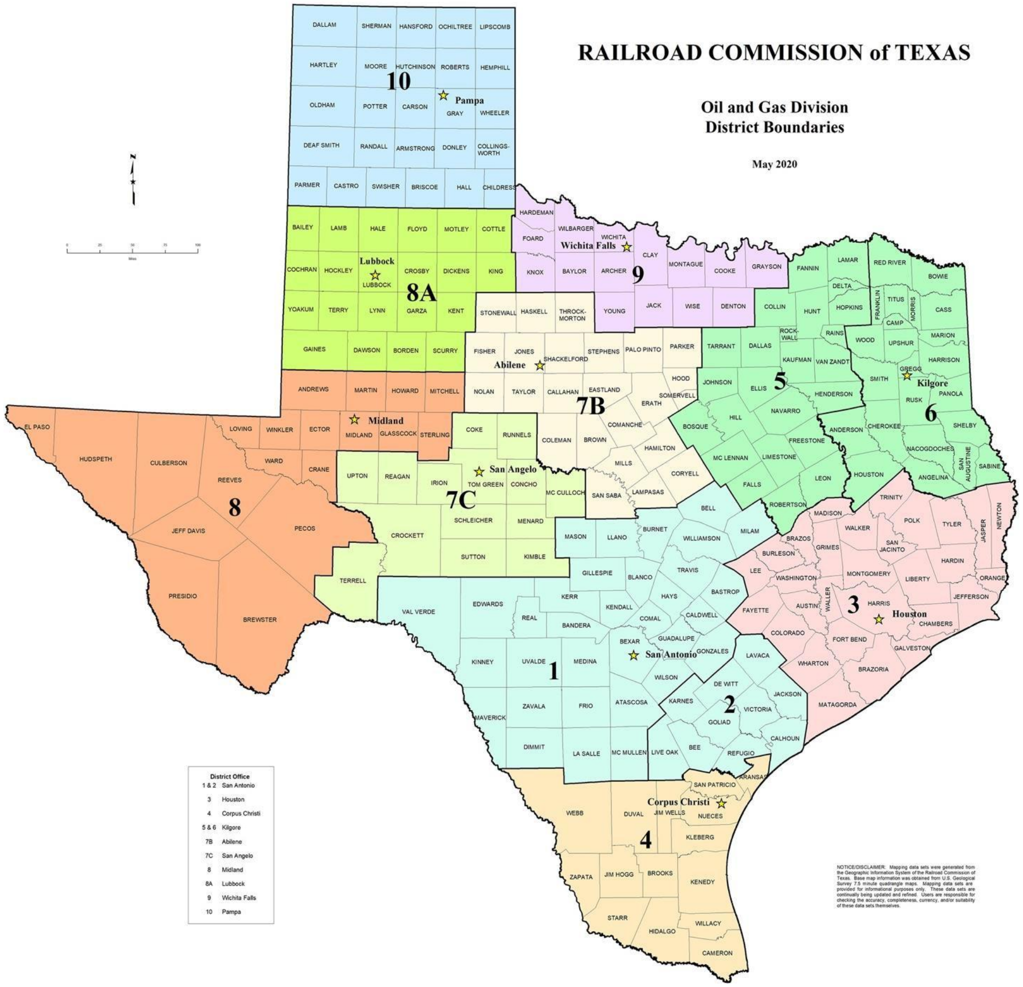

Figure 5. Texas oil and gas districts (used with permission from the Railroad Commission of Texas)

Natural gas prices are reported both at the census and OGSM region level and can be used to produce a weighted average price for the PADD Gulf Coast region. The NGMM reports natural gas pipeline capacities and flows using natural gas regions as shown in **Figure 6**. New Mexico is part of the 'Arizona and New Mexico' region and are reported as a proportion benched to current capacity. The other five states in the PADD Gulf Coast region are part of the South Central region and are reported as a proportion benched to current capacity.

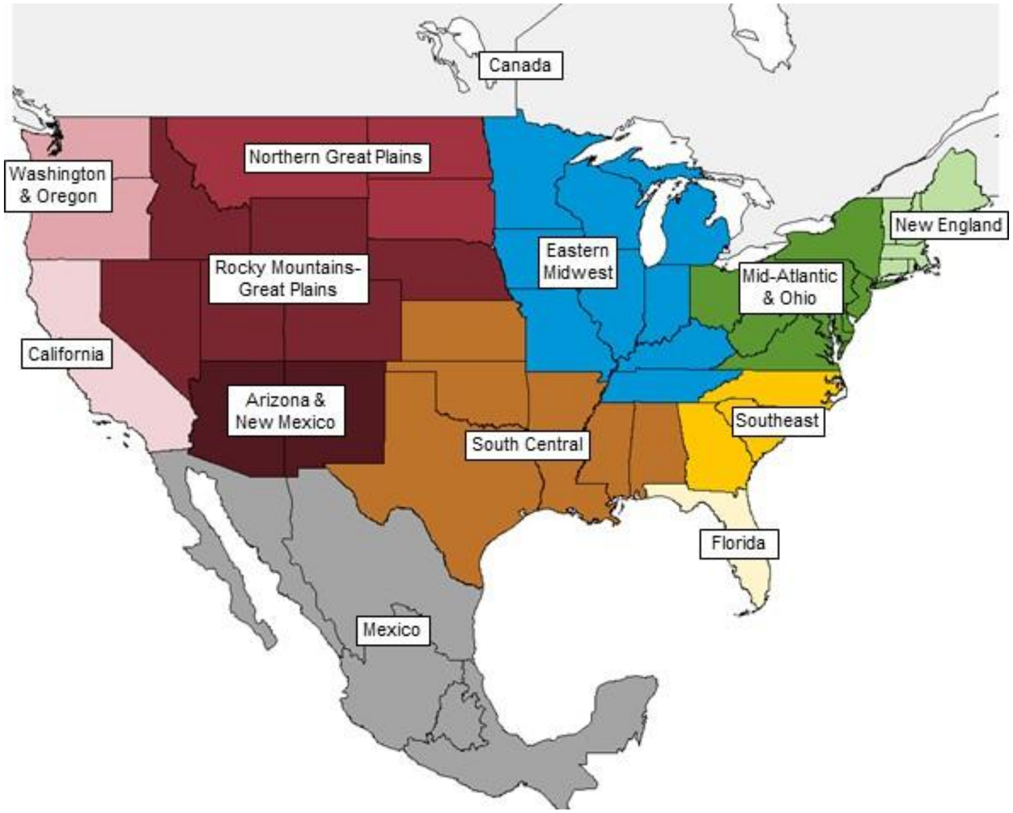

Figure 6. Natural gas regions (source: EIA)

Regional Reporting for Power

The price of electricity calculated in the EMM is provided to each demand sector at the census region level, as shown in **Figure 1**. OL-NEMS reports the generation using different power technologies including NGCC plants. The EMM uses North American Electric Reliability (NERC) regions (**Figure 7**) for reporting that do not neatly conform to state boundaries. However, OL-NEMS can look at which region each state is roughly falling in for most of its generation. New Mexico is part of region 20, so OL-NEMS uses its share of total generation for reporting (~33% in 2023). Texas is mostly covered by region 1 (ERCOT) and can be represented directly. Arkansas, Louisiana, and part of Mississippi can be mapped to region 6. Alabama is part of region 15, so OL-NEMS uses its share of total generation (~50% in 2023) for reporting. These historical shares are available from EIA (2024c).

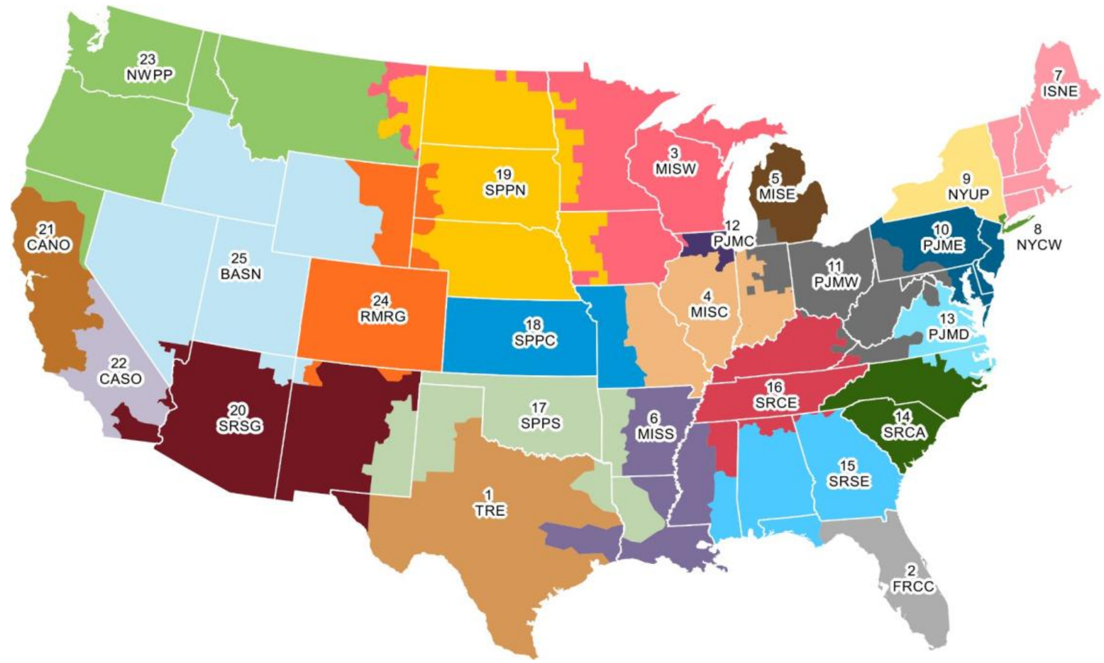

Figure 7. Electricity supply regions (used with permission from NERC)

CO_2 Transport & Storage Cost

The cost of CO_2 T&S is calculated in the Carbon, Transport, Storage and Utilization (CTUS) sub-module within OL-NEMS. CTUS builds a least cost pipeline network to either send CO_2 captured from various sources to saline sequestration or for use in enhanced oil recovery (EIA, 2020). This cost is also available to the other modules at the fuel region level.

Business-as-Usual (BAU) Scenarios

2023 Annual Energy Outlook Reference Case

In EIA's AEO23 Reference case (referred to as AEO23 in the modeling results in Appendix H), an assessment of how U.S. and world energy markets would operate through 2050 is made under current laws and regulations as of November 2022 under evolutionary technological growth assumptions. The key assumptions in this case provide a baseline, or experimental control, for exploring long-term trends.

OL-NEMS 2024 Reference Case

While AEO23 and OL-NEMS have many underlying assumptions in common, there are some key differences:

- OL-NEMS includes updated policies and regulations that have been passed since AEO23 was published, including new Environmental Protection Agency (EPA) GHG standards for both power plants and vehicles, select appliance standards, and state-level policies, including zero-emission vehicles and mandates for battery storage and offshore wind.
- OL-NEMS provides a more complete representation of the IRA provisions, including tax credits for clean fuels, H_2, and direct air capture, and implements additional Bipartisan Infrastructure Law (BIL) provisions, including funding for advanced nuclear and CO_2 capture demonstration plants and CO_2 pipeline and storage subsidies.
- OL-NEMS assumes lower costs for renewable and carbon capture technologies, and for electric vehicles, and greater data center electricity demand growth in the commercial sector, along with many other policy and data updates.
- OL-NEMS assumes a combination of updated policies and regulations and lower technology costs, resulting

in a more rapid phase-out of conventional fossil fuels in favor of renewables, including solar, wind, and biofuels, and electric vehicles.

- OL-NEMS assumes total primary consumption is higher primarily due to higher growth in electricity sales, driven primarily by additional data centers.

Note that this case is referred to as Reference in the results shown in Appendix H.

Low Oil & Gas Supply

Compared to the OL-NEMS 2024 Reference, the Low Oil & Gas Supply (Low OGS) scenario assumes that 1) the estimated ultimate recovery per well for tight oil, tight gas, or shale gas in the United States; 2) the undiscovered resources in Alaska and the offshore Lower 48 states; and 3) rates of technological improvement, are all 50% lower.

This scenario assumes support for the market adoption of emerging fuels, based on the expectation that their competitiveness with oil and gas will improve as delivery infrastructure becomes more available.

High Economic Growth, High Zero-Carbon Technology Cost

This scenario explores the adoption of emerging fuels in a high economic growth market where zero-carbon technology costs remain high. It assumes the compound annual growth rate for U.S. gross domestic product (GDP) is 2.3%. By contrast, the AEO23 Reference and OL-NEMS 2024 Reference cases assume the U.S. GDP annual growth rate is 1.9%.

This scenario also considers the sensitivities around capital costs for electricity-generating technologies that produce zero emissions, which include renewables, nuclear, and diurnal storage technologies. The capital costs are assumed to decline over time from learning by doing as commercialization expands and construction and manufacturing experience accelerates.

Emerging Fuel Pathway Evaluation Inputs and Assumptions

LCA and TEA are baseline analyses of individual technologies within each fuel pathway that help establish technology priorities. Firstly, LCA uses upstream emissions intensity of feedstocks for each technology (natural gas consumption, electricity consumption) to determine GHG intensity (a.k.a. carbon intensity, CI). Similarly, TEA analyses calculate a levelized cost of production of decarbonized fuel based on individual cost components, including any available credits that can depend on technology CI. Variables for these LCA and TEA calculations can depend on subregion within the Gulf Coast.

The OL-NEMS model uses subregion LCA and TEA results, as well as specifications from the BAU and emerging fuel pathway scenarios. Variables include technologies employed, available policies/credits, consumer behavior, and international interactions. The goal for this model is to calculate long-term energy projections (supply, demand, and price). Compared to the LCA and TEA calculations, this model determines a time series of data to project the effect of fuel use choices.

The CBA relates the OL-NEMS results to real-world decisions. It calculates breakeven CO_2 emissions prices, above which the use of a particular pathway can help to provide consumers with cost-effective fuels that lead to a lower carbon footprint. These breakeven CO_2 emissions prices are provided for each technology within all pathways. The lower breakeven prices identify pathways and technologies with the greatest potential for success.

Appendix C: 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 (Theis, 2019). 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 (Theis, 2019) 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**.

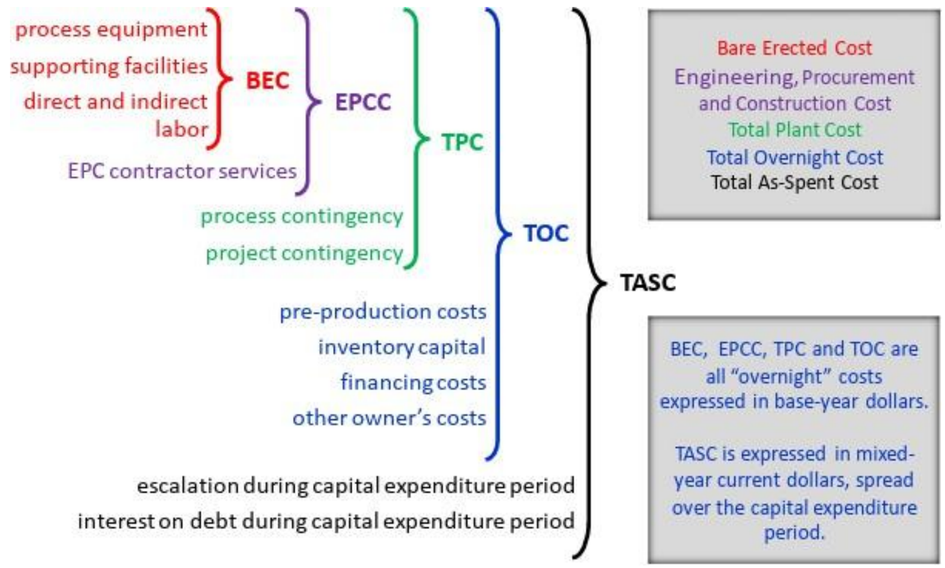

Figure 8. Capital cost levels and their elements [source: NETL (Theis, 2019)

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.

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

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.

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

The VOMCs are proportional to the operating capacity of the plant and include electricity costs, consumable costs, waste disposal costs, maintenance material costs, coproduct sales, and CO_2 T&S. The coproduct sales considered include carbon black from the plasma pyrolysis case (H2-7) and electricity exported to the grid in the gasification to RNG cases (RNG-1 to RNG-3). 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.

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

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 considered to be estimated unweighted levelized costs of electricity (LCOEs) for new resources entering service in 2027 (EIA, 2022b), and more assumptions for the LCOE calculation can be found in the AEO Levelized Costs report (EIA, 2022b).

Appendix D: 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. 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, the default parameters for all pathways for U.S. production are generally used unless otherwise specified. Specifically, for the low-carbon H_2 production cases that require RNG (e.g., RNG-fed ATR with CCS), the NG input is set to 100% RNG in the Main Inputs section and the user-override feature is used to place the upstream emission contribution from RNG (kg CO_2e/kg RNG), which gets included in the total GHG impact results of that specific H_2 production scenario. This approach helps include the impact analysis results of RNG production from the latest attributional LCA of U.S. RNG production pathways (Henriksen et al., 2025 [release forthcoming]), which updates prior published work by this team (Rai, Hage, Littlefield, Yanai, & Skone, 2022). The new report was updated with the biogenic emissions being tracked throughout the production system and essentially looks at two system boundaries: 1) feedstock is treated as a true waste and, thus, has no upstream impacts attributed to it (including biogenic CO_2 uptake) and 2) upstream feedstock impacts are included along with biogenic CO_2 uptake. For the purpose of this LCA, the expanded system case (accounts for displaced emissions from carbon uptake) of anaerobic digestion of MSW is considered. The results from this case range from -7.08 to 11.2 g CO_2e/MJ RNG.

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 the U.S. Environmental Protection Agency [EPA] Greenhouse Gas Reporting Program [GHGRP]) 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 9.** 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%.

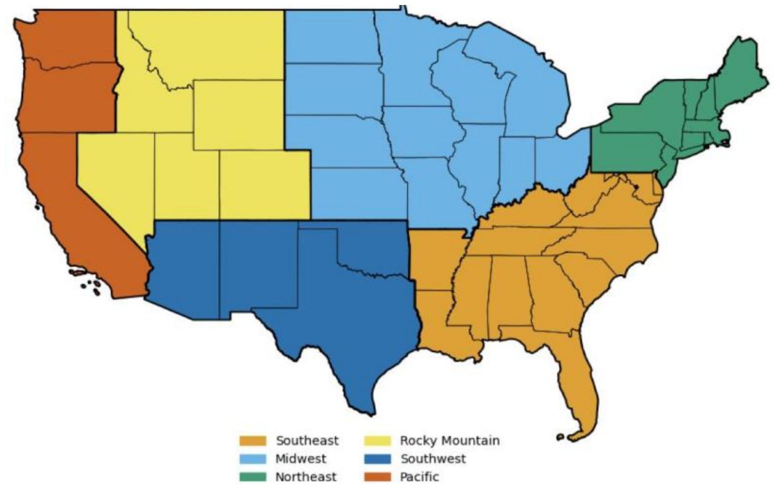

Figure 9. Delivery regions for natural gas in the U.S. used in the NETL NG Baseline (Khutal, et al., 2024)

A summary of the total GHG intensities (across all the six upstream production stages) associated with these delivery regions and the U.S. average is shown in **Table 1**.

Table 1. Summary of GHG intensities of natural gas delivery (Khutal, et al., 2024)

Region	Mean GHG Intensity (g CO_2e/MJ)
U.S. Average	8.8
Midwest	9.7
Northeast	7.3
Pacific	12.3
Rocky Mountain	12.5

Southeast	11.0
Southwest	10.4

While the regional boundaries between the NETL and GTI Energy/PADD definitions are generally similar, the differences in constituent states leads to varying intensities reported for each region. To meet the requirements of this project, the values for the PADD-defined regions were calculated by leveraging results from the NETL/GTI Energy delivery regions from the Kutal et al. study, as described below. This was done using EIA state-level natural gas consumption data (2024d) (as used in the previous study to apportion delivery region demand) as a basis to transform values between the available and needed regional bases. For example, to determine the PADD Gulf Coast basin GHG intensity of natural gas production, the NETL/GTI values for the Southeast and Southwest regions were combined (the resulting mean value would be 10.4–11.0 g CO_2e/MJ).

Table 2 reports the resulting state-level greenhouse gas intensities.

Table 2. Natural gas basin and state-level GHG intensities

State	Gas Supply Region	Basin Intensity (g CO_2e/MJ)	State Intensity (g CO_2e/MJ)
New Mexico	Southwest (Permian Basin)	11.3	11.8
	San Juan Basin	12.3	
Texas	Gulf Coast Onshore (Southeast)	10.4	10.7
	Permian/Southwest	11	
Arkansas	Midcontinent/Appalachia Mix (Southeast)	10.4	10.4
Louisiana	Gulf Coast (Southeast)	10.4	10.4
Mississippi	Gulf Coast (Southeast - Delivery)	10.4	10.4
Alabama	Gulf Coast (Southeast - Delivery)	10.4	10.4

In general, since the intensities only vary by about 10% between adjacent regions (and all are within about 20% of the U.S. average), the re-mapping to PADD regions does not add significant uncertainty to the results.

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 (NETL, n.d.), and publicly available source code for generating custom grid mixes (EPA, n.d.). Additionally, as a part of the analysis done in prior work (Redublo, et al., 2023) 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.

The OHI toolkit provides the contribution of the upstream electricity usage to the overall global warming potential (GWP) of producing 1 kg of H_2. The analysis for each H_2 production pathway is run for every individual balancing authority (this selection can be made in the Main Inputs tab of the toolkit). These numbers are then used to generate the average upstream electricity contribution to the overall impact on a state level— which can then be added to the total GWP value (without the upstream electricity impact included).

Results from the Electricity Power Markets report and models provide GHG emission intensity from electricity production for the 10 FERC market regions, and for the 68 balancing authorities in the U.S. The FERC regions for electricity are shown in **Figure** 10.

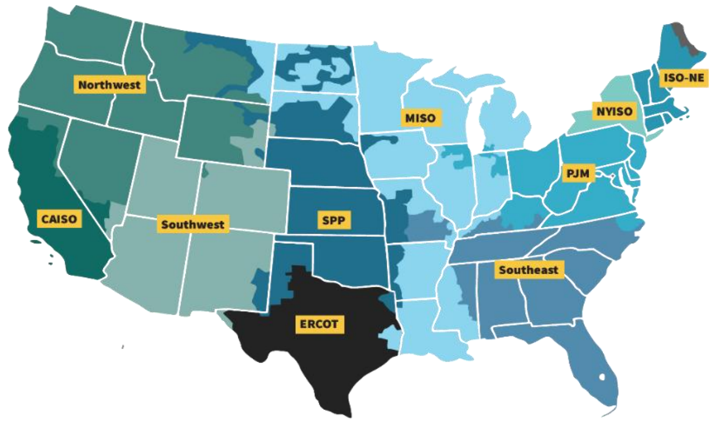

Figure 10. FERC electricity regions (FERC, n.d.)

As an example,

Table 3 summarizes an excerpt of data from the Grid Mix Explorer v4.2 for the GHG intensity of upstream electricity values that can be used in the pathway carbon intensity estimates by region.

Table 3. Summary of GHG intensities of electricity production (NETL, n.d.)

Region	Mean GHG Intensity (kg CO_2e/MWh)
U.S. Average	600
ERCOT	663
MISO	766
SPP	703
Southeast	583

Southwest	604

Similar to the conversion mapping from the NETL/GTI Energy study regions to the PADD regions, values from the FERC regions will be aligned with the PADD-defined 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. Based on previous work,

Table 4 shows an example mapping of the state to FERC regions.

A weighted GHG intensity for each region 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 significant change the results. Given the use of consumption data, the electricity intensity for the PADD-defined Gulf Coast region will be like the value of 663 from the Electric Reliability Council of Texas (ERCOT), which is composed of most of Texas.

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

Table 4. Electricity balancing authority (BA) and state-level GHG intensities

State	Balancing Authorities (BAs)	BA Annual Net Generation (TWh)	BA Intensity (kg O2e/MWh)	State Intensity (kg O2e/MWh)
New Mexico	SPP	276	482	532
	WAPA - Rocky Mountain	38	875	
	Public Service Company of New Mexico	17	588	
Texas	SPP	276	482	491
	ERCOT	470	428	
	MISO	653	541	
Arkansas	MISO	653	541	524
	SPP	276	482	
Louisiana	MISO	653	541	524
	SPP - Western Louisiana	276	482	
Mississippi	MISO	653	541	510
	SERC	251	431	

Alabama	SERC	251	431	475
	MISO - Northern Alabama	653	541	
	Tennessee Valley Authority	165	282	

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 and SNG 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.

H_2 Pathways Inputs and Outputs

Fossil-based H_2 production pathways

Table 5. OHI inputs for fossil-based H_2 production pathways

	H2-1 NG-fed w/ CCS	H2-2 NG-fed ATR w/ CSS	H2-7 Plasma Pyrolysis
Natural Gas Mix	100% Fossil Natural Gas	100% Fossil Natural Gas	
Electricity Mix	100% Grid electricity	100% Grid electricity	100% Grid electricity

CO_2 Capture Location	From shifted gas using MDEA and flue gas MEA (90% net capture)		
Nitrogen co-production		Yes	
Grid Electricity Location	United States of America	United States of America	United States of America
Balancing Authority	U.S. Average	U.S. Average	
Process Definition			
Inputs			
Electricity (kWh)		4.01	38.6
Natural Gas (kg)	3.73	3.52	0.61
Water (kg)	4.9	24.35	215
Embodied Emissions (kg CO_2e)	1.45E-04	0.00	0.001408269
Outputs			
Captured CO_2 (kg)	9.81	8.81	
Carbon Dioxide (kg)	1.09	0.52	2.61
Methane (kg)			0.03
Carbon Black (kg)			3.54
Electricity Co-product (kWh)	0.05	0.00	
Nitrogen Co-product (kg)	0	14.65	
Electricity Mix			
Biomass	0.70%	0.70%	0.70%
Coal	17.20%	17.20%	17.20%
Geothermal	0.50%	0.50%	0.50%
Hydroelectric	9.80%	9.80%	9.80%
Natural Gas	40.00%	40.00%	40.00%

Nuclear	19.70%	19.70%	19.70%
Oil	0.10%	0.10%	0.10%
Solar Photovoltaic	3.80%	3.80%	3.80%
Solar Thermal	0.10%	0.10%	0.10%
Wind	8.20%	8.20%	8.20%
Natural Gas			
Country where natural gas is being sources from	United States of America (the)	United States of America (the)	United States of America (the)
Do you want to use default impact values for all stages ?	Yes	Yes	Yes
Is the distribution stage relevant to your system?	No	No	No
Is there a storage step in your system?	Yes	Yes	Yes
Select upstream production techno-basin:	U.S. Average	U.S. Average	U.S. Average
Select downstream delivery region:	Southwest	Southwest	Southwest
Include avoided emissions?		Yes	

RNG-based H_2 production pathways

Table 6. OHI inputs for RNG-based H_2 production pathways

	H2-3 RNG-fed SMR	**H2-4 RNG-fed ATR w/o CSS**	**H2-5 RNG-fed SMR w CCS**	**H2-6 RNG-fed ATR w**

	w/o CSS			CCS
Natural Gas Mix	100% Renewable Natural Gas	100% Renewable Natural Gas	100% Renewable Natural Gas	100% Renewable Natural Gas
Electricity Mix	100% Grid electricity	100% Grid electricity	100% Grid electricity	100% Grid electricity
CO_2 Capture Location			From shifted gas using MDEA and flue gas MEA (90% net capture)	
Nitrogen co-production	No	Yes	No	Yes
Grid Electricity Location	United States of America	United States of America	United States of America	United States of America
Balancing Authority	U.S. Average	U.S. Average	U.S. Average	
Process Definition				
Inputs				
Electricity (kWh)	0	3.25	1	4.01
Natural Gas (kg)	3.4	3.52	3.74	3.52
Water (kg)	6.31	24.35	4.45	24.35
Embodied Emissions (kg CO_2e)	0.000123033	0.000151023	0.000128373	0.000151023
Outputs				

Captured CO_2 (kg)	0	0	8.9	8.81
Carbon Dioxide (kg)	9	9.33	0.99	0.52
Electricity Co-product (kWh)	1.1	0	0.05	0
Nitrogen Co-product (kg)	0	14.65	0	14.65
Electricity Mix				
Biomass	0.70%	0.70%	0.70%	0.70%
Coal	17.20%	17.20%	17.20%	17.20%
Geothermal	0.50%	0.50%	0.50%	0.50%
Hydroelectric	9.80%	9.80%	9.80%	9.80%
Natural Gas	40.00%	40.00%	40.00%	40.00%
Nuclear	19.70%	19.70%	19.70%	19.70%
Oil	0.10%	0.10%	0.10%	0.10%
Solar Photovoltaic	3.80%	3.80%	3.80%	3.80%
Solar Thermal	0.10%	0.10%	0.10%	0.10%
Wind	8.20%	8.20%	8.20%	8.20%
Natural Gas				
Include avoided emissions ?	Yes	Yes	Yes	Yes

Electrolytic H_2 production pathways

The scenario labeled H2-8 refers to electrolysis powered by a low-carbon electricity mix which was originally constructed by proportionally scaling the renewable components of the U.S. grid mix (as defined in the OHI Toolkit) to 100%, effectively removing all non-renewable sources. Earlier in the project, internal LCA work used interim designations like H2-8A, H2-8B, and H2-8C to explore uncertainty in this low-carbon mix, but these intermediate cases were not included in the final report. Instead, the study now reports a distinct set of cases (H2-8a through H2-8e and H2-8(a+b)), each representing electrolysis paired with a specific renewable source (e.g., solar, wind, nuclear, etc.). These are the only H2-8 subcases included in the final LCA results.

Table 7. Electrolytic H_2 production pathways

	H2-8 PEM Electrolysis Grid Mix	**H2-8a PEM Electrolysis with Solar**	**H2-8b PEM Electrolysis with Wind**	**H2-8c PEM Electrolysis with Nuclear**	**H2-8d PEM Electrolysis with Hydro**	**H2-8e PEM Electrolysis with Biofuels**
Natural Gas Mix	100% Fossil Natural Gas					
Electricity Mix	100% Grid electricity					
Oxygen co-production	Yes					
Grid Electricity Location	United States of America					
Balancing Authority	U.S. Average					
Process Definition						
Inputs						
Electricity (kWh)	38.6	38.6	38.6	38.6	38.6	38.6
Natural Gas (kg)	0.61	0.61	0.61	0.61	0.61	0.61

Water (kg)	215	215	215	215	215	215
Embodied Emissions (kg CO_2e)	0.00140827	0.001408269	0.001408269	0.001408269	0.001408269	0.001408269
Outputs						
Fugitive H_2 (kg)	0.034	0.034	0.034	0.034	0.034	0.034
Oxygen Co-product (kg)	14.65	14.65	14.65	14.65	14.65	14.65
Electricity Mix						
Biomass	3.00%	0				100%
Geothermal	2.20%					
Hydroelectric	42.40%				100%	
Natural Gas	0.00%			100%		
Solar Photovoltaic	16.50%	50%				
Solar Thermal	0.40%	50%				
Storage	0.00%					
Wind	35.50%		100%			
Natural Gas						
Country where natural gas is being sources from	United States of America	United States of America	United States of America	United States of America	United States of America	United States of America
Do you want to use	Yes	Yes	Yes	Yes	Yes	Yes

default impact values for all stages ?						
Is the distribution stage relevant to your system?	No	No	No	No	No	No
Is there a storage step in your system?	Yes	Yes	Yes	Yes	Yes	Yes
Select upstream production techno-basin:	U.S. Average	U.S. Average	U.S. Average	U.S. Average	U.S. Average	U.S. Average
Select downstream delivery region:	Southwest	Southwest	Southwest	Southwest	Southwest	Southwest
Include avoided emissions ?	Yes	Yes	Yes	Yes	Yes	Yes

RNG-Specific Modeling Details

The following table summarizes the specific parameters used for analysis of RNG for the cited work above. The report evaluates several feedstocks (e.g., MSW, animal manure, wastewater sludge) and technologies (anaerobic digestion, LFG recovery, and thermal gasification), comparing the GWP results under two system boundary cases: the "true waste" case, where feedstocks are considered burden-free waste, and the "expanded system" case, which includes the upstream impacts of feedstock production and credits for co-products and biogenic carbon uptake. The report incorporates process data from GREET, WARM, OHI, and NETL databases, and modeling is conducted in openLCA using IPCC AR6 100-year characterization factors. For the anaerobic digestion of MSW in the expanded system case, the analysis finds a net-negative climate impact, with a lower bound GWP of -7.08 g CO_2e/MJ RNG, largely due to avoided emissions and biogenic CO_2 uptake outweighing the emissions from processing. This is the value used as the upstream RNG emissions impact input for calculating the GWP of RNG-based H_2 pathways.

Table 8. GWP and electricity requirements used for RNG production pathways

Production Pathway	GWP (kg CO_2e/MJ RNG)	Electricity Requirements	Unit of Measurement
Woody Feedstock (Air Gasification)	222	0.07515	MJ/MJ dirty syngas
MSW (Anaerobic Digestion)	-7.08	2.20823	MJ/MJ dirty biogas

SNG-Specific Modeling Details

The following tables describe parameters needed for the SNG pathways analysis, taken from the openLCA model for SNG. The openLCA modeling for SNG production used in this analysis was developed to evaluate the life cycle GHG emissions associated with producing SNG through various CO_2 utilization (CO_2U) pathways. The model simulates cradle-to-gate impacts of SNG production using different combinations of H_2 sources (such as electrolysis powered by grid electricity or biomass gasification) and point-source CO_2 from facilities like cement, ethanol, or steel plants. The functional unit is 1 MJ of SNG, and the modeling incorporates assumptions about upstream energy use, process energy inputs, and methanation efficiency. The openLCA model uses IPCC AR6 100-year GWPs and includes system expansion in select cases to account for displaced grid electricity or other co-products. The model assumes that CO_2 is captured and delivered to the methanation reactor with minimal losses and that H_2 production is the dominant contributor to total GHG emissions, with electricity source and efficiency being key drivers.

The current SNG openLCA model includes multiple H_2 production pathways, each broadly defined and intended to feed into the SNG production process. Separate openLCA models are available for CCS units, and specific flows from these can be imported into the SNG model as proxies to construct targeted scenarios for GHG results. However, incorporating these external CCS flows into each H_2 production pathway requires careful alignment of reference flows and system boundaries, which can be time intensive. Among the available H_2 production technologies—PEM, Solid Oxide, and Alkaline Electrolysis—only the Alkaline Electrolysis pathway currently includes integrated CO_2 capture from NGCC and ethanol processes. As a result, this pathway was selected for use in the current analysis to streamline integration and maintain internal consistency within the model.

Table 9. SNG-Specific Modeling Details

Catalytic Methanation (AE+Cement CO_2)								
Inputs				**Contribution Tree**				
Input Flow	Amount	Unit	Provider	Process	Required amount	Unit	Total result [kg CO_2e]	Direct contribution [kg CO_2e]
carbon dioxide	2.644120739	kg	Cement retrofit; capture unit (95% capture)	H_2 Mixer	0.481951316	kg	14.95390962	0
Electricity, AC, 120 V	1.65834311	kWh		Electricity; at user; consumption mix - US - US	5.970035197	MJ	0.985215807	0

H_2, >99.90 vol%, 925 psig (6.48 MPa)	0.481951316	kg		Steel, sections, production - GLO	0.075745942	kg	0.122719712	0.122719712
natural gas, delivered	5.72E-06	kg		Natural Gas Emissions Profile, US Weighted Average - 2017	5.72E-06	kg	4.52E-06	4.52E-06
Nickel-based catalyst	6.33E-04	kg		Cement retrofit; capture unit (95% capture)	2.644120739	kg	-2.333440188	-2.644120739
steel	0.075745942	kg						
Air	1.688223166	kg						
Water	0.003406326	kg						
Outputs				**Impact Analysis**				
Syngas	1	kg		Global Warming Potential [100 yr] - TRACI 2.1 (NETL)	13.72840947	kg CO_2e		
Water	2.126662977	kg		Carbon dioxide	12.57886589	kg CO_2e		
				Methane	1.083997553	kg CO_2e		
Catalytic Methanation (AE+CO_2 at ethanol plant)								
Inputs				**Contribution Tree**				
Input Flow	Amount	Unit	Provider	Process	Required amount	Unit	Total result [kg CO_2e]	Direct contribution [kg CO_2e]
Carbon dioxide, processed	2.644120739	kg	Carbon dioxide processing, ethanol plant - US	H_2 Mixer	0.481951316	kg	14.95390962	0
Electricity, AC, 120 V	1.65834311	kWh		Electricity; at user; consumption mix - US - US	5.970035197	MJ	0.985215807	0
H_2, >99.90 vol%, 925 psig (6.48 MPa)	0.481951316	kg		Steel, sections, production - GLO	7.57E-02	kg	1.23E-01	0.122719712
natural gas,	5.72E-06	kg		Natural Gas Emissions Profile, US	5.72E-06	kg	4.52E-06	4.52E-06

delivered				Weighted Average - 2017				
Nickel-based catalyst	6.33E-04	kg		Carbon dioxide processing, ethanol plant - US	2.644120739	kg	-1.559953752	0
Catalytic Methanation (AE+Cement CO_2)								
steel	0.075745942	kg						
Air	1.688223166	kg						
Water	0.003406326	kg						
Outputs				**Impact Analysis**				
Syngas	1	kg		Global Warming Potential [100 yr] - TRACI 2.1 (NETL)	14.5018959	kg CO_2e		
Water	2.126662977	kg		Carbon dioxide	13.21554066	kg CO_2e		
				Methane	1.137718094	kg CO_2e		
Catalytic Methanation (AE+NGCC CO_2)								
Inputs				**Contribution Tree**				
Input Flow	Amount	Unit	Provider	Process	Required amount	Unit	Total result [kg CO_2e]	Direct contribution [kg CO_2e]
carbon dioxide	2.644120739	kg	NGCC Power Plant, capture, cradle-to-gate - US-IL	H_2 Mixer	0.481951316	kg	14.95390962	0
Electricity, AC, 120 V	1.65834311	kWh		NGCC Power Plant, capture, cradle-to-gate - US-IL	2.644120739	kg	1.037049458	1.037049458
H_2, >99.90 vol%, 925 psig (6.48 MPa)	0.481951316	kg		Electricity; at user; consumption mix - US - US	5.970035197	MJ	0.985215807	0
natural gas, delivered	5.72E-06	kg		Steel, sections, production - GLO	0.075745942	kg	0.122719712	0.122719712

Nickel-based catalyst	6.33E-04	kg		Natural Gas Emissions Profile, US Weighted Average - 2017	5.72E-06	kg	4.52E-06	4.52E-06
steel	0.075745942	kg						
Air	1.688223166	kg						
Water	0.003406326	kg						
Outputs				**Impact Analysis**				
Syngas	1	kg		Global Warming Potential [100 yr] - TRACI 2.1 (NETL)	17.09889911	kg CO_2e		
Water	2.126662977	kg		Carbon dioxide	15.44862278	kg CO_2e		
				Methane	1.585241607	kg CO_2e		
Catalytic Methanation (AE+Steel CO_2)								
Inputs				**Contribution Tree**				
Input Flow	Amount	Unit	Provider	Process	Required amount	Unit	Total result [kg CO_2e]	Direct contribution [kg CO_2e]
Catalytic Methanation (AE+Cement CO_2)								
Carbon dioxide, processed	2.644120739	kg	Steel, sections, production w/ CC - GLO	H_2 Mixer	0.481951316	kg	14.95390962	0
Electricity, AC, 120 V	1.65834311	kWh		Steel, sections, production w/ CC - GLO	2.644120739	kg	3.602848942	3.021064578
H_2, >99.90 vol%, 925 psig (6.48 MPa)	0.481951316	kg		Electricity; at user; consumption mix - US - US	5.970035197	MJ	0.985215807	0
natural gas, delivered	5.72E-06	kg		Steel, sections, production - GLO	0.075745942	kg	0.122719712	0.122719712
Nickel-based catalyst	6.33E-04	kg		Natural Gas Emissions Profile, US Weighted Average - 2017	5.72E-06	kg	4.52E-06	4.52E-06
steel	0.075745942	kg						
Air	1.688223166	kg						

Water	0.003406326	kg						
Outputs				**Impact Analysis**				
Syngas	1	kg		Global Warming Potential [100 yr] - TRACI 2.1 (NETL)	19.6646986	kg CO_2e		
Water	2.126662977	kg		Carbon dioxide	18.16539554	kg CO_2e		
				Methane	1.383595457	kg CO_2e		

Appendix E: Cost-Benefit Analysis (CBA)

Methodology

The CBA synthesizes the results of the NEMS model, TEA study, and LCA study to identify the most viable technology pathway to net-zero. The CBA adds one key metric in the form of the "Required Incentive" calculation, which provides an alternative metric for evaluating each technology. Related to discussions around the implementation of a carbon tax or carbon credits (45Q and 45V are known examples of ways these can be implemented), it can theoretically provide lawmakers with an idea of what economic stimulus would be necessary to promote the adoption of some of the technologies being explored by this study. This is essentially a "break-even" CO_2 emissions price, which can be interpreted either as a cost avoided in the case of a tax, or an additional revenue stream in the case of a credit.

The incentives were calculated using the following equation:

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

where LC is the levelized fuel cost of the renewable fuel or natural gas respectively, in $/MMBtu, and CI is the carbon intensity of the fuel in tons of CO_2/MMBtu. These numbers were all calculated based on the mass higher heating values of the fuels in question, which were assumed to be 22,500 Btu/lb for natural gas and all similar fuels and 61,084 Btu/lb for H_2. Both of these numbers were acquired from Engineering Toolbox (2005).

Assumptions

The CBA synthesizes the results of the NEMS model, TEA study, and LCA study to identify the most viable technology pathway to net-zero. All assumptions and methodologies used for these studies, thus, also apply to the CBA.

Findings

The LCA case for MSW, based on a biodigester, is the only case in the LCA results for the Gulf Coast that yields negative CO_2

emissions. Since no other numbers are available, despite not being based on the same case, the levelized cost of $40.97/MMBtu was used to determine the CO_2 incentive. This was determined to be a reasonable estimate since biodigesters and thermal gasifiers tend to have similar costs, and both cases make use of the same feedstock. The specific number calculated by the TEA is also within the range from a previous study from Pratson Fay, and Parvathukar (2023). The result of this calculation revealed an incentive of $156.91/ton of CO_2, owed primarily due to the highly negative CO_2 emissions.

Further justification of the results is provided by several references from DOE's Clean Hydrogen Liftoff Report (Howe, O'Dell, Rustagi, & Christian, 2024), the Electric Power Research Institute and GTI Energy Regional Pipeline Costs Study using their REGEN model (EPRI, 2024), and DOE's Cost and Performance Baseline Volume 1 Report on fossil energy plants (Schmitt, et al., 2022). Other references were provided solely for background information.

Appendix F: Estimated End-Use Demand in the Region

H_2 Petroleum Industry Demand

The majority of H_2 demand in the region is driven by petroleum refineries, with Texas making up the largest share. Refineries utilize H_2 extensively for processes such as hydrocracking and desulfurization, making them the dominant H_2 end-users. Louisiana also has a significant number of petroleum refineries, but its H_2 demand is more tied to ammonia production. It is anticipated that the petroleum industry in Texas and Louisiana will continue to be the largest off-takers of H_2 in the Gulf Coast region.

H_2 Industrial and Power Sector Demand

Currently, the power generation and iron and steel industries in the Gulf Coast region do not utilize H_2. Due to the region's abundant and low-cost natural gas supply, these industries utilize natural gas for electricity generation and industrial heat applications. The higher cost and limited supply have constrained this sector's transition to H_2. As production scales up and regulatory incentives are available to make H_2 more cost-competitive, the industrial and power generation sector may adopt H_2. However, there will be a need for significant advancements in large-scale H_2 power generation and industrial heat technologies to enable the transition.

H_2 Transportation Demand

The Gulf Coast region's transportation sector currently has minimal demand for H_2, with Texas having less than 0.01 petajoules of demand. The limited H_2 demand in the transportation sector is largely due to the region's well-developed electric charging, ethanol, propane, and CNG fueling infrastructure. However, long-haul trucking has potential to be a significant H_2 end-user in the future. H_2 refueling is considerably faster than electric charging (i.e., 10 to 15 minutes versus several hours), which is an advantage that helps avoid disruptions to logistics and supply chains. As major manufacturers (e.g., Hyundai, Volvo, Toyota) continue to develop their H_2-powered heavy-duty trucks and as decarbonization incentives grow, it is anticipated that there will be a greater demand for H_2 in the transportation sector.

Appendix G: Estimated Costs and Emissions

Producing and Delivering Emerging Fuels in Each State

The Hydrogen Delivery Scenario Analysis Model (HDSAM), developed by Argonne National Laboratory, was used to determine costs of H_2 transportation and delivery (Elgowainy & Reddi, 2022). Region-specific factors such as electricity prices, natural gas price, and labor costs were incorporated into HDSAM to provide estimates more specific to the Gulf Coast region, and all prices are reported in 2023$. Besides these adjustments, all default assumptions in the HDSAM were maintained. Both liquid and gaseous transportation and delivery options were analyzed (**Table 10**).

Table 10. Summary of liquid and gaseous delivery costs by H_2 capacity

H_2 Capacity (kg/day)	Liquid Delivery Transport Cost (2023$/kg H_2)	Gaseous Delivery Transport Cost (2023$/kg H2)
500	16.36	6.22
5,000	5.99	2.12
50,000 (~Electrolyzer Scale)	3.57	1.69
500,000 (~SMR Scale)	2.90	1.64
5,000,000	2.82	1.63

The liquid option includes an H2 liquefier at the production facility, a liquid H_2 terminal, and a liquid H_2 delivery truck. Key assumptions include a liquefier of 200,000 kg/day capacity with multiple units for larger demands and a 120 km round-trip delivery distance (Elgowainy & Reddi, 2022). The gaseous option includes compression at the production facility, a gaseous H_2

terminal, and transport via tube truck. Key assumptions include 120 km round-trip delivery distance and average round-trips around 3.7 per day (Elgowainy & Reddi, 2022). The same information has been graphed in **Figure 11**, with the x-axis on a logarithmic scale. This shows the impact of economies of scale on H_2 delivery.

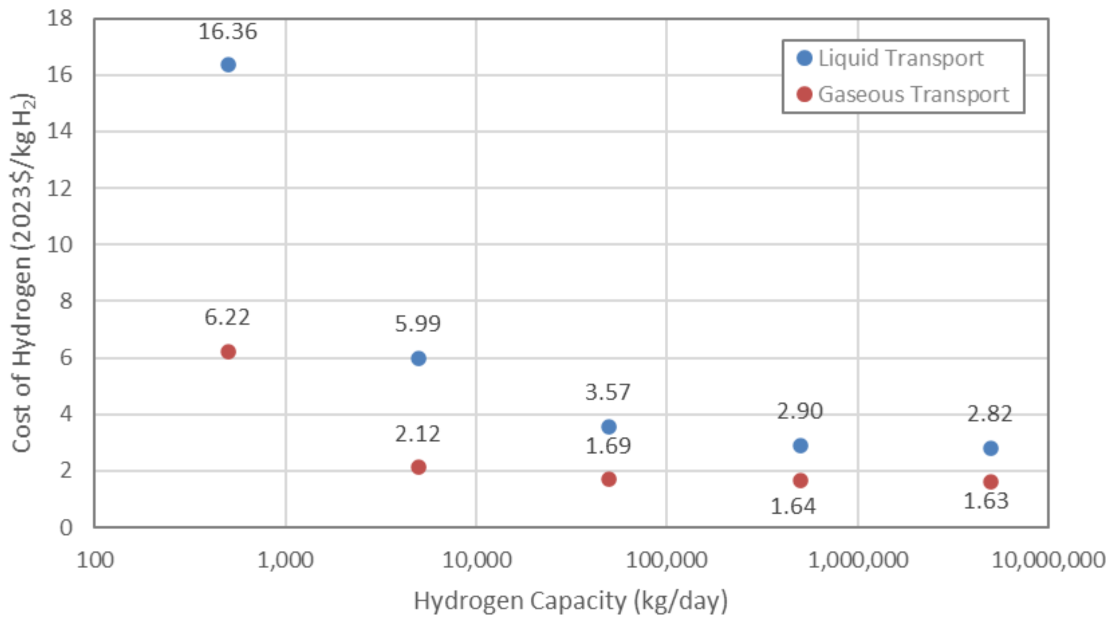

Figure 11. Graphical representation of H_2 delivery costs

End-Use Costs and Emissions of H_2 Blends

Power Generation Costs

For a back-of-the- envelope estimate, the lower heating value (LHV) of H_2, 33.3 kWh/kg (The Engineering ToolBox, 2003), is used to determine its energy content. The Kawasaki Heavy Industries' L30A turbine can achieve 40.3% efficiency (Kawasaki, 2025) when operating on H_2.

Production Emissions

The base SNG pathways (SNG-1 through SNG-4) were developed in openLCA using several unit processes, where each pathway represents a unique carbon source (e.g., NGCC flue gas, cement, steel, ethanol) paired with H_2 produced via grid-powered electrolysis. These models include upstream feedstock production, CO_2 capture, methanation, and compression steps, and reflect detailed inventory flows (e.g., electricity, water, chemical use) per kg SNG produced. The openLCA calculations use U.S. average grid electricity impacts based on NETL and eGRID data to quantify the cradle-to-gate GWP using AR6 100-year characterization factors.

For the alternative SNG cases (e.g., SNG-1a through SNG-1e), where electrolysis is powered by a single renewable or low-carbon source (solar, wind, nuclear, hydro, biomass), the full openLCA model was not rebuilt for each electricity mix due to modeling complexity and time constraints. Instead, this analysis adopted a streamlined approach by isolating the electricity-related GHG contribution from the openLCA output and adjusting it externally. This was done by multiplying the electricity demand of electrolysis (assumed to be 5.97 MJ electricity per kg SNG) by literature-based carbon intensities of electricity sources (e.g., 15 gCO_2e/MJ for solar from NREL/Argonne National Laboratory's Greenhouse Gases, Regulated emissions, and Energy use in Technologies (GREET), 11 for wind, 12 for nuclear, etc.). These adjusted values were then added back to the non-electricity GHG contributions from the original openLCA model to produce total GWP per kg SNG for each electricity source and state.

While this method does not reflect all potential upstream or regional variations (e.g., construction burdens or energy storage requirements), it provides a technically grounded estimate of the impact of switching electricity sources on the GHG intensity of SNG production. Modeling each variation directly in openLCA would require creating or modifying multiple background processes for each electricity mix, along with careful parameter control to reflect regional power flows—a more precise but significantly more time-intensive process.

RNG-1A represents a true waste boundary case, which begins at the receipt of forest thinning at the production facility. All upstream biomass production and carbon uptake is excluded (Henriksen et al., 2025 [release forthcoming]). This is consistent with ISO 14040/14044—compliant attributional modeling practices for waste feedstocks—where CO_2 uptake is only credited if the system includes biomass production. Therefore, no avoided emissions are credited, and no displacement of fossil natural gas or upstream sequestration benefits are included. This is aligned with ISO 14067 guidance, which warns against mixing consequential assumptions (e.g., displacement or avoided emissions) with attributional frameworks unless fully justified and documented. Including credits for avoided fossil gas combustion or downstream use would introduce methodological inconsistencies and is not supported in most ISO-compliant LCAs unless using consequential modeling (which this study does not adopt). Additionally, CO_2 uptake from biomass is only considered in the expanded system, shown in the RNG-1B case. In the true waste case, biogenic CO_2 is neither assigned a GWP of zero nor a negative value—it is excluded entirely, in line with attributional principles for end-of-life residues. Assigning a GWP of zero across the board for biogenic CO_2 without tracking fate or residence time would conflict with AR6 guidance and is explicitly avoided in this model.

Appendix H: NEMS Results Summary

Emissions

Total emissions in 2050 are lowest in the Low OGS case, resulting from lower energy availability and, therefore, macroeconomic growth. In the LowC H_2 cases, 20% blending cases have lower total emissions than 5% blending cases. Among individual sectors, emissions are lowest in the commercial and residential sectors in the SNG 20% case (**Figure 12**).

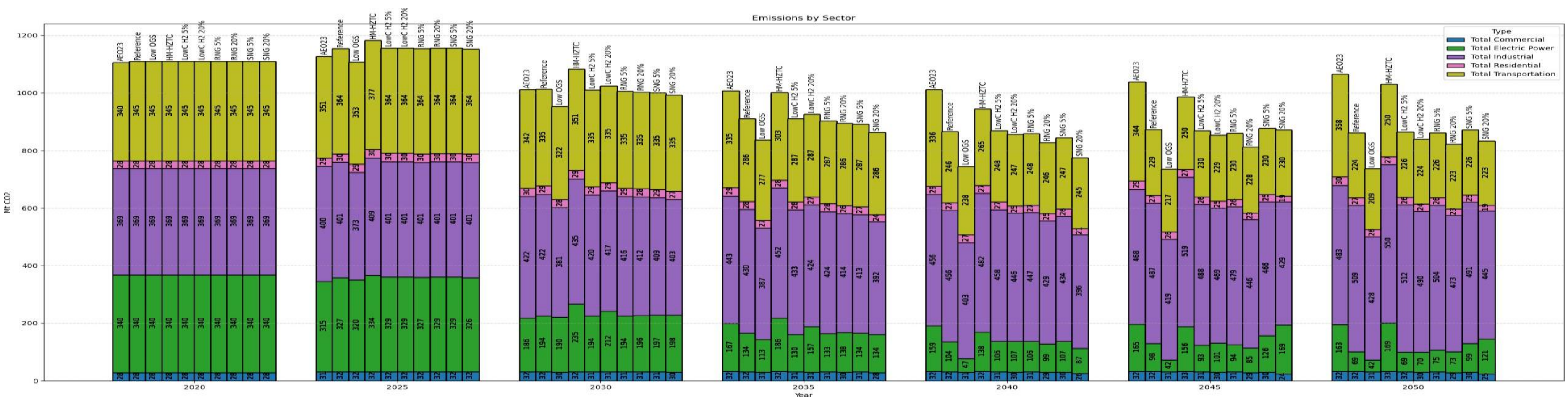

Figure 12. Emissions by sector

Power Sector

Generation

In all cases except the AEO23, power generation from coal is nearly zero by 2050. The generation increases in the SNG 5% case and dramatically so in the SNG 20% cases, with the latter showing increases across most technologies except coal and petroleum. Most of the increase in the SNG 20% cases is seen in renewables (**Figure 13**).

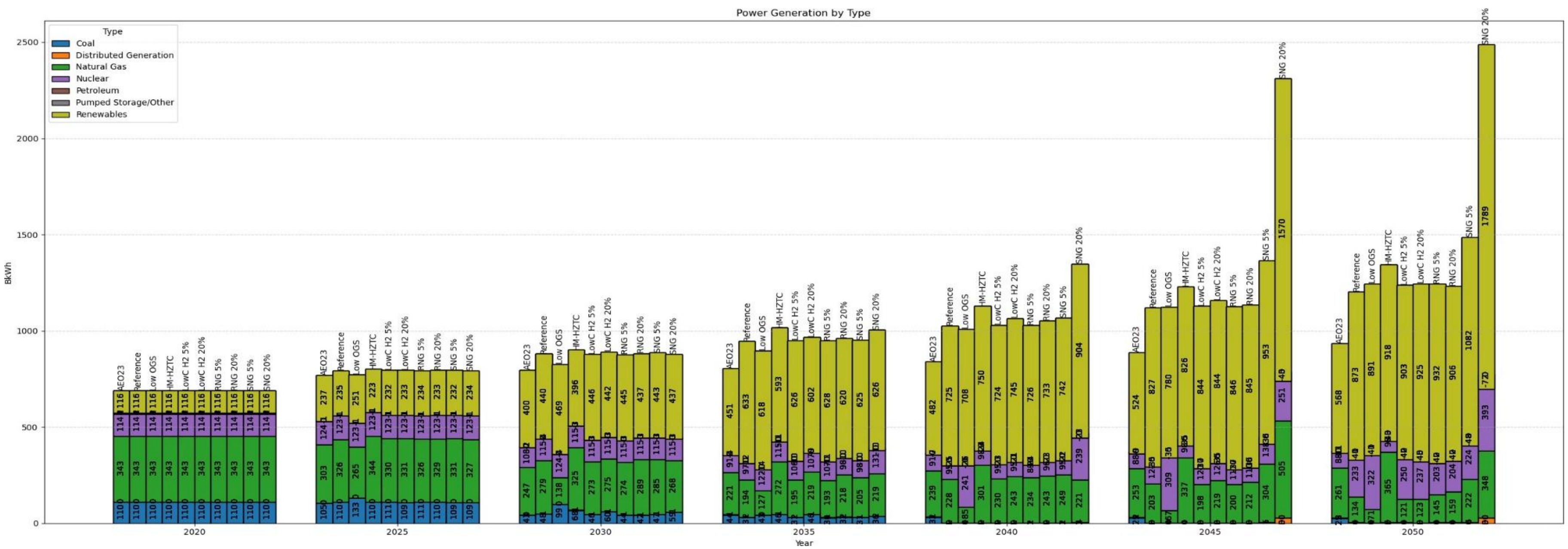

Figure 13. Power generation by type

Capacity

Power capacity shows similar trends to power generation. In all cases except the AEO23, coal power capacity is nearly zero by 2050. The capacity increases in the SNG 5% case and dramatically so in the SNG 20% cases, with the latter showing increases across most technologies except coal, nuclear, and gas turbines. Most of the increase in the SNG 20% cases is seen in renewables (**Figure 14**).

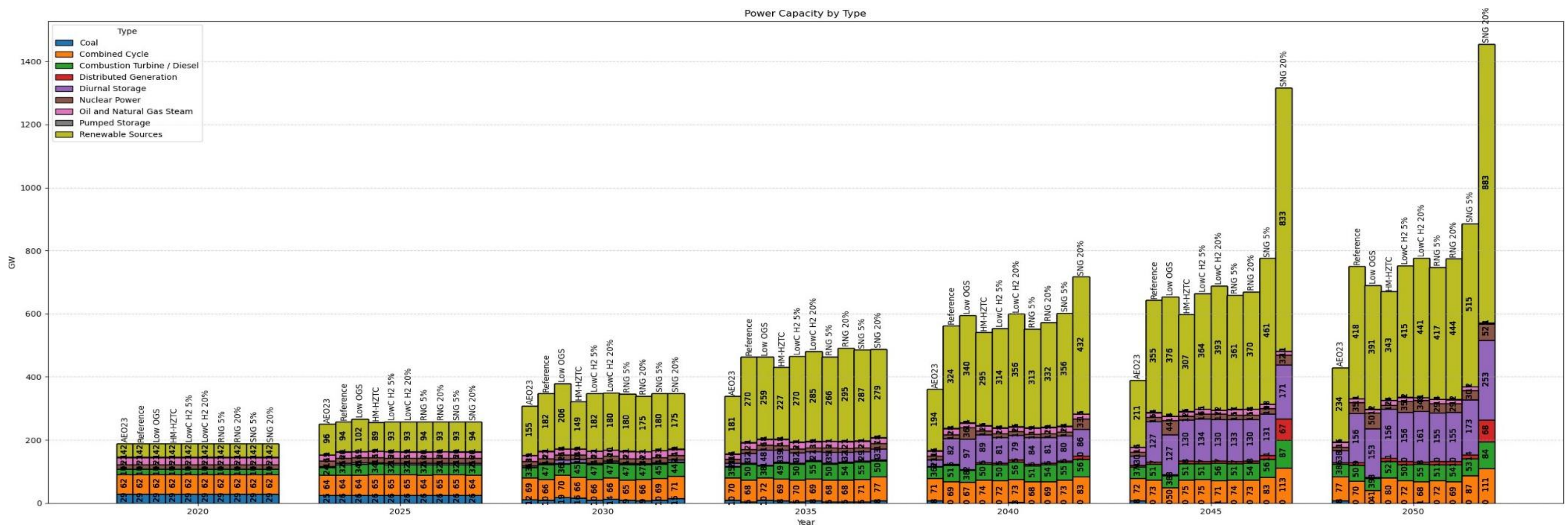

Figure 14. Power capacity by type

Sales

Power sales to H_2 and industry increase in the SNG 5% case and dramatically so in the SNG 20% cases. This is due to the constraint on producing H_2 for SNG production primarily via electrolysis (**Figure 15**).

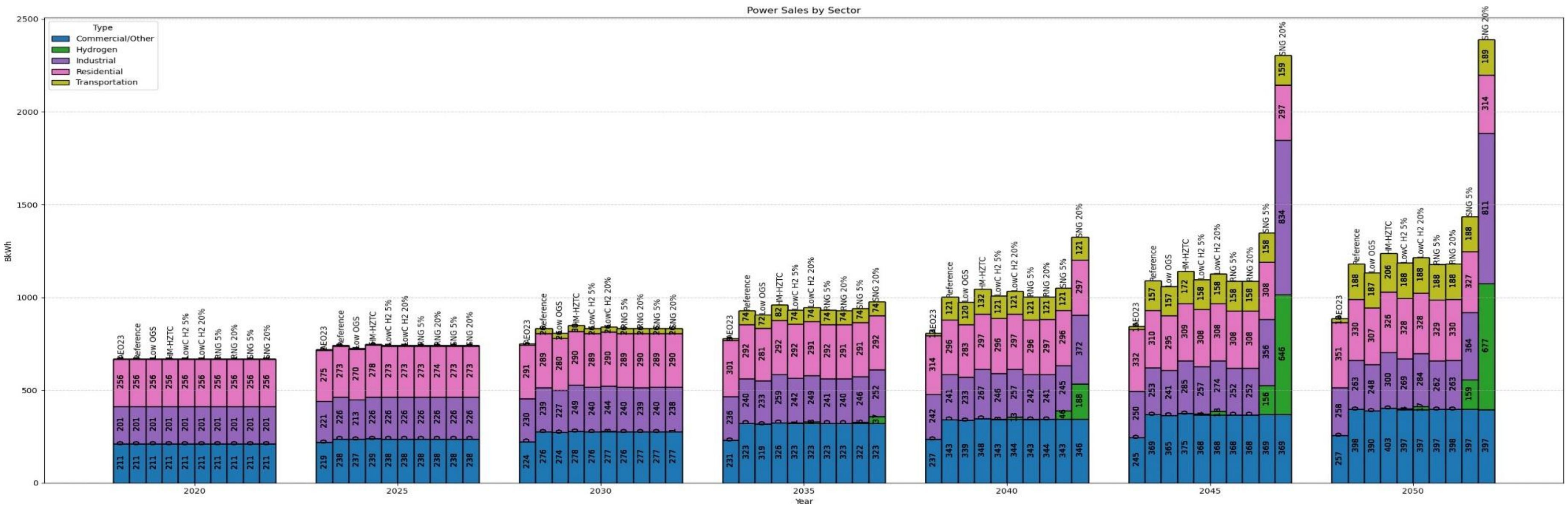

Figure 15. Power sales by sector

Prices

Due to the constraint on producing H_2 for SNG production primarily via electrolysis in the SNG cases, the power price to industrial (which is also used by H_2) and to residential sectors is dramatically higher in those cases (**Figure 16**).

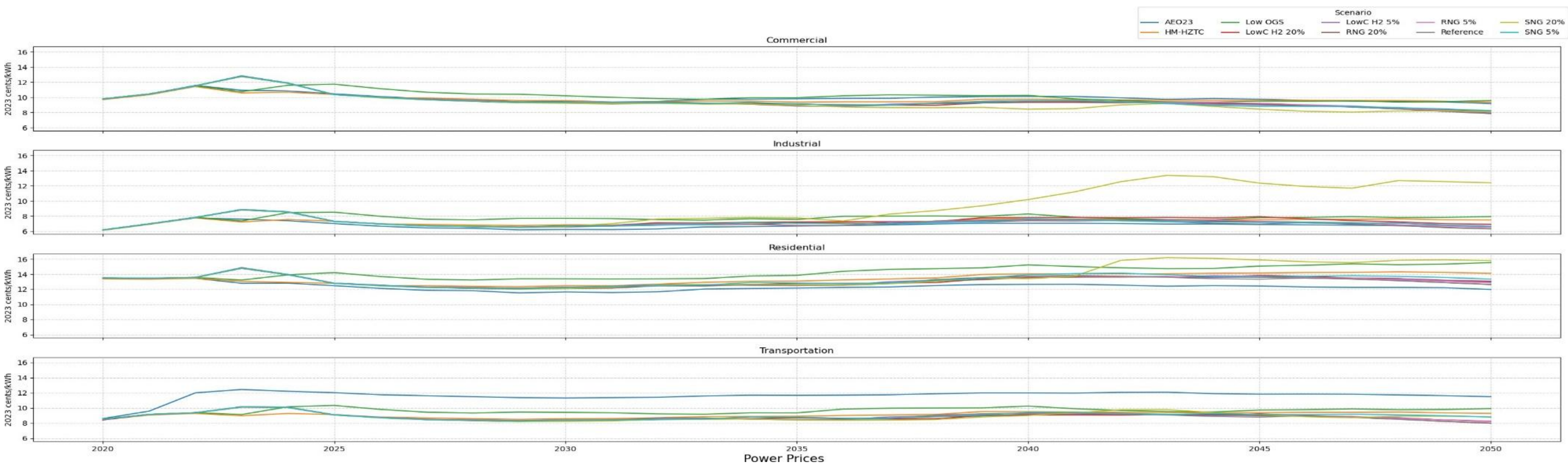

Figure 16. Power prices

Natural Gas

Henry Hub Prices

Except for the low OGS case, which results in higher spot prices at the Henry Hub, the other scenarios have consistent prices. The SNG 20% case has slightly high prices in later years due to increased NG demand in the power sector (**Figure 17**).

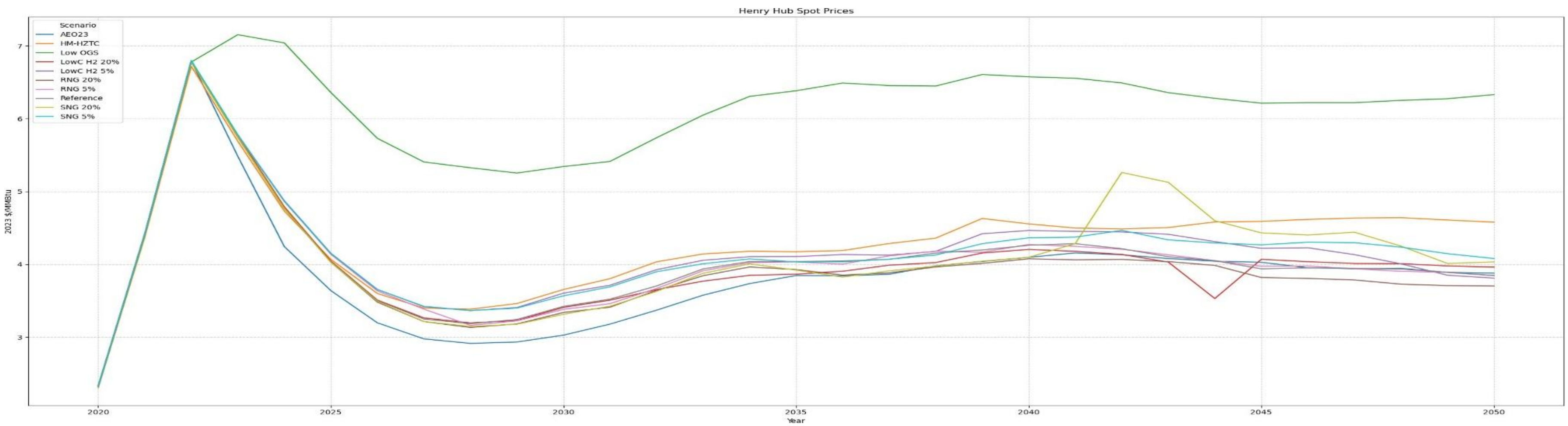

Figure 17. Henry Hub spot prices

Delivered Prices

Similar to the spot prices, except for the low OGS case, which results in delivered NG prices, the other scenarios have consistent prices. The SNG 20% case has slightly high prices in later years due to increased NG demand in the power sector (**Figure 18**).

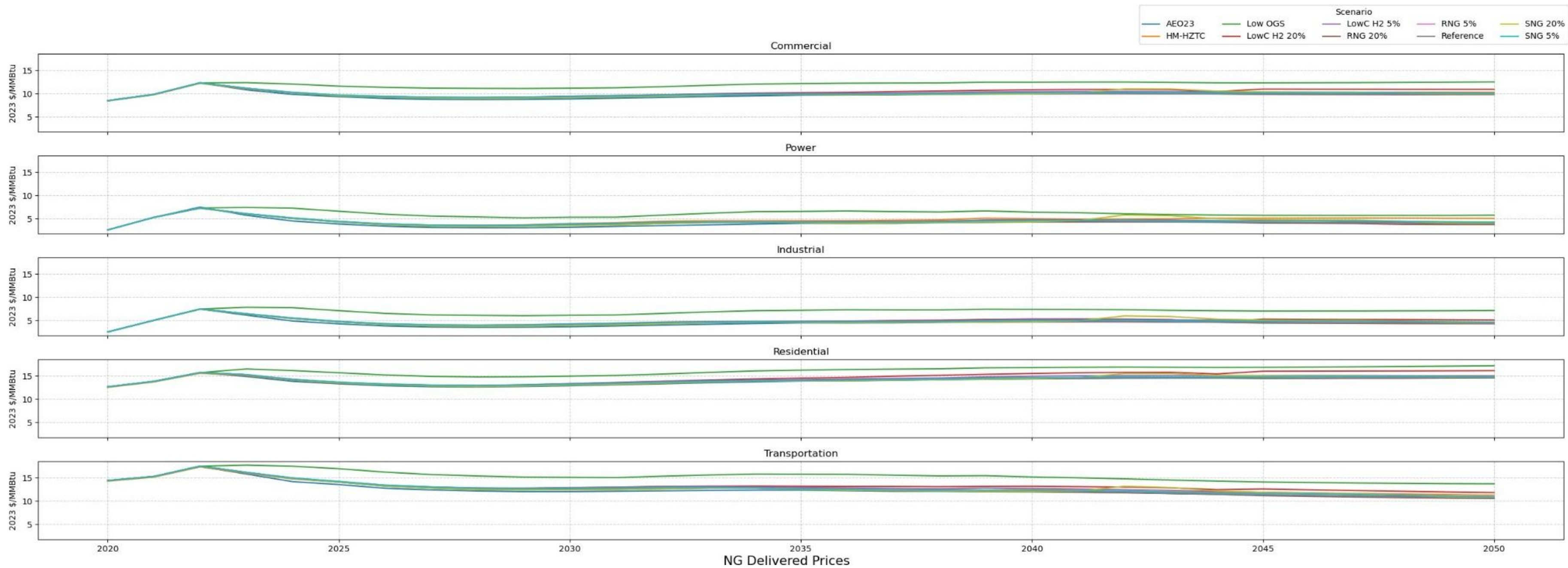

Figure 18. NG delivered prices

LNG Exports

LNG exports are lowest in the Low OGS case. All other cases show high LNG exports except in the HM-HZTC and LowC H_2 20% cases, which are slightly lower in 2050 (**Figure 19**).

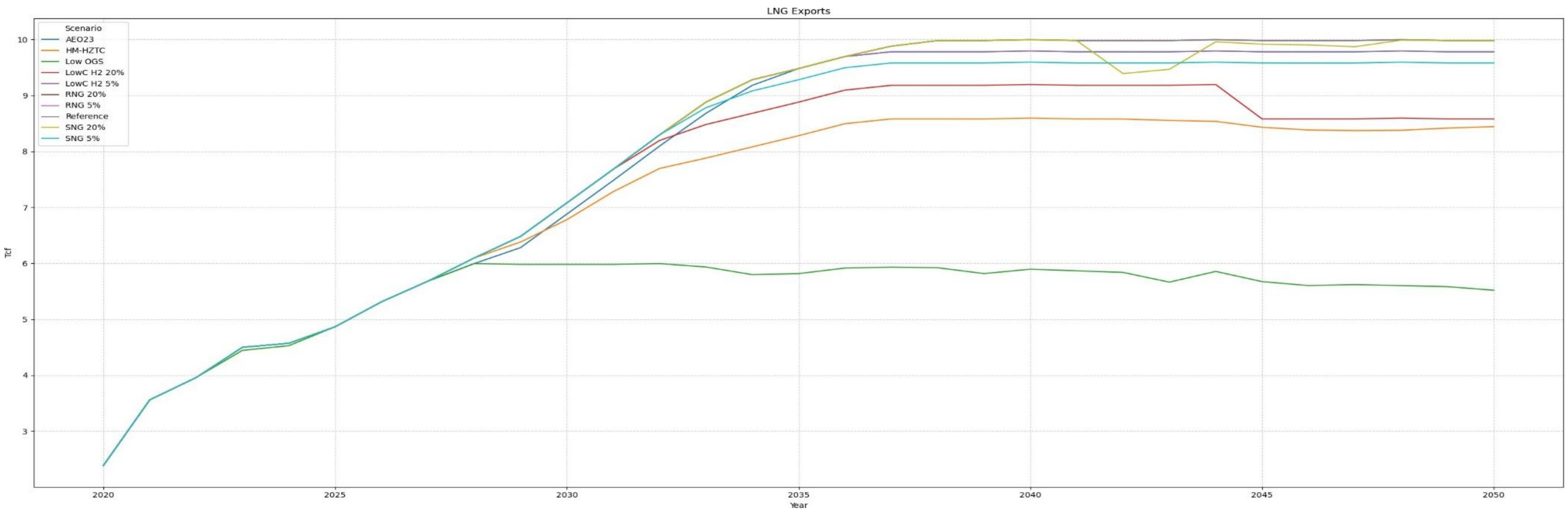

Figure 19. LNG exports

Consumption

The total consumption is lowest in the Low OGS case, while the highest levels are seen in the HM-HZTC and SNG cases, particularly in the power sector. In the LowC H_2 cases, high demand from the H_2 sector is compensated by lower demand in the industrial sector due to displacement of NG as fuel in industry by H_2 (**Figure 20**).

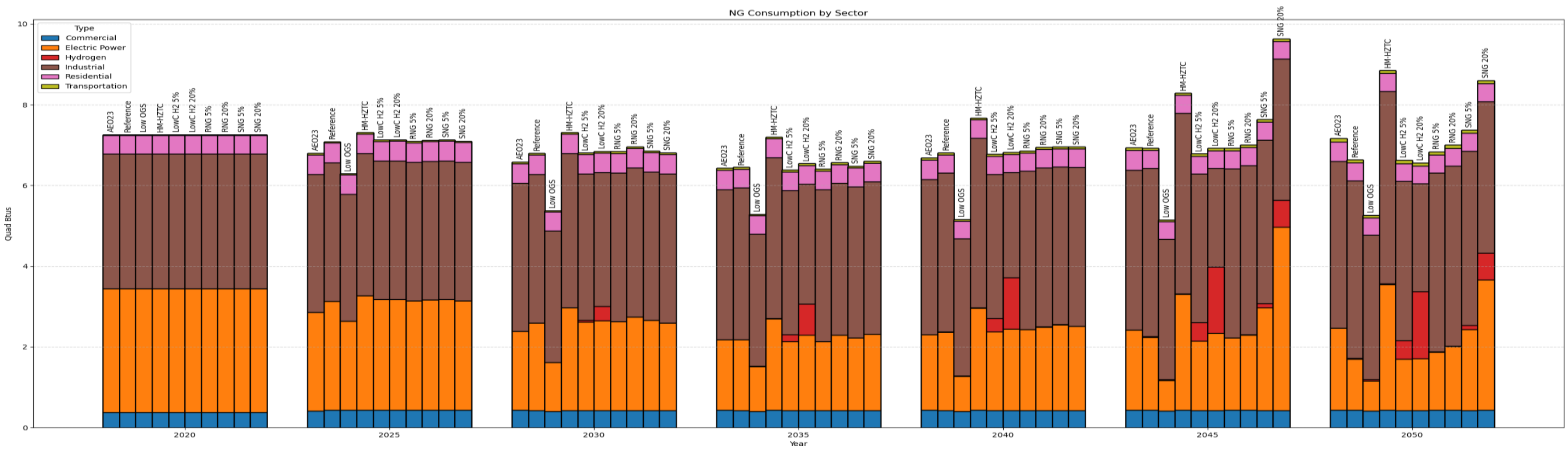

Figure 20. NG consumption by sector

Production

Conventional production declines in all cases while shale production increases in all but the Low OGS case. Tight gas production increases in both the HM-HZTC and SNG 20% cases due to higher demand (**Figure 21**).

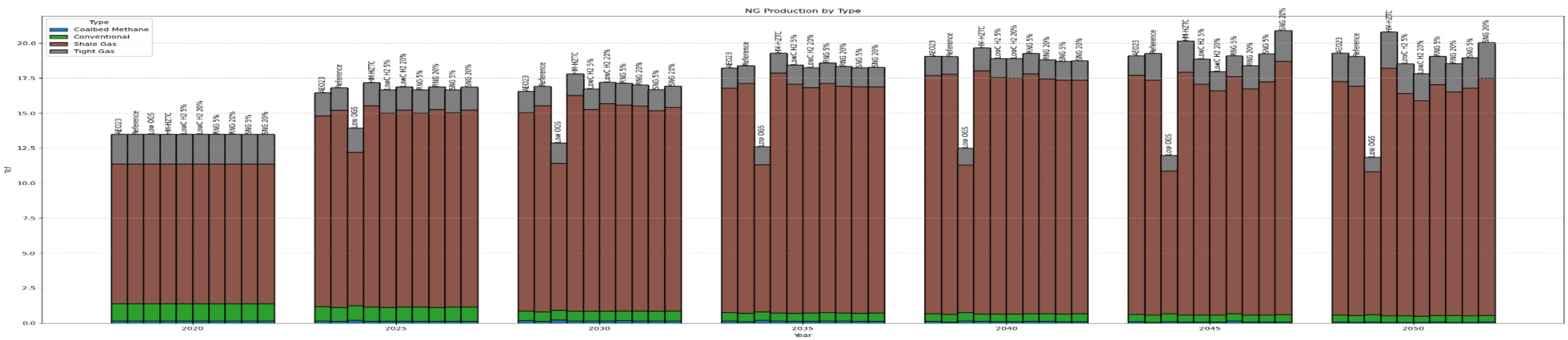

Figure 21. NG production by type

Hydrogen

Production

In the LowC H_2 cases, the production is mainly from SMR/ATR with CCS, and in the SNG cases it is from proton exchange membrane electrolysis. There is virtually no production in the other cases. Production from RNG technologies is also zero in all cases due to the high cost of RNG compared to NG and Electricity (**Figure 22**).

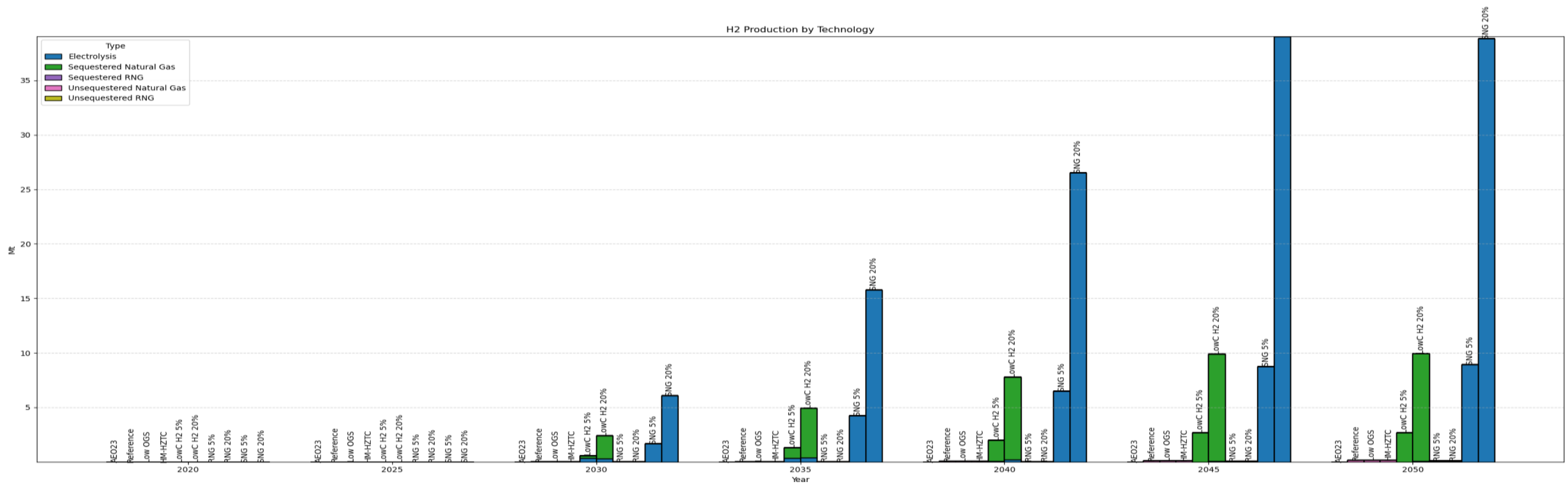

Figure 22. H_2 production by technology

Demand

H_2 demand increases dramatically in the LowC H_2 blending and SNG blending cases, the latter due to demand for H_2 in SNG production. There is virtually no demand in the other cases (**Figure 23**).

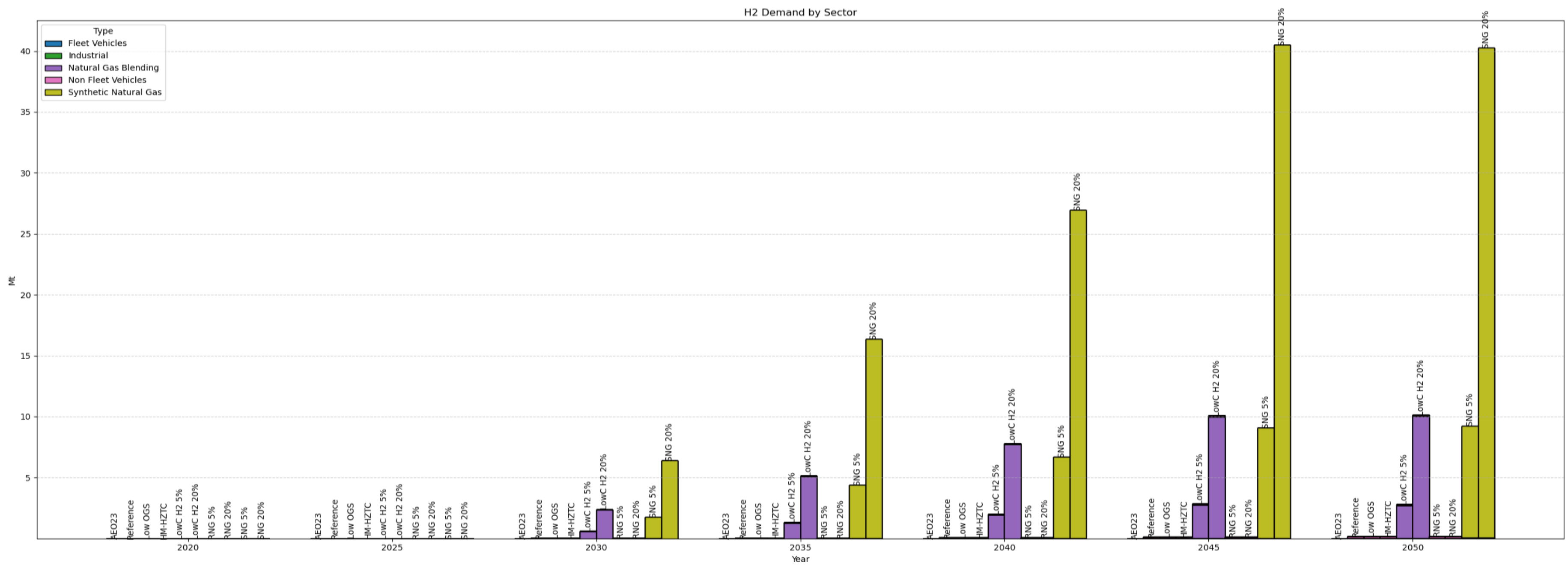

Figure 23. H_2 demand by sector

Prices

H_2 prices are highest in the SNG 20% case due to the production being mainly through electrolysis. There is not much difference in the delivered price to different sectors except for the transport adder (**Figure 24**).

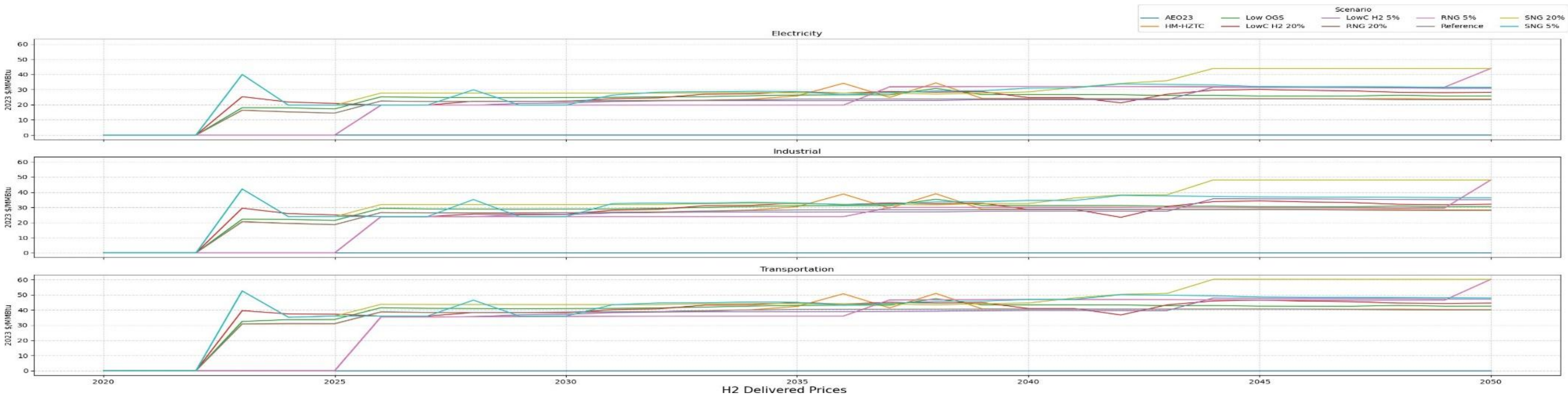

Figure 24. H_2 delivered prices

RNG/SNG Prices

RNG Production

RNG production is only present in the RNG blending cases and scales with the percentage of blending. No H_2 is produced from RNG in any of the cases (**Figure 25**).

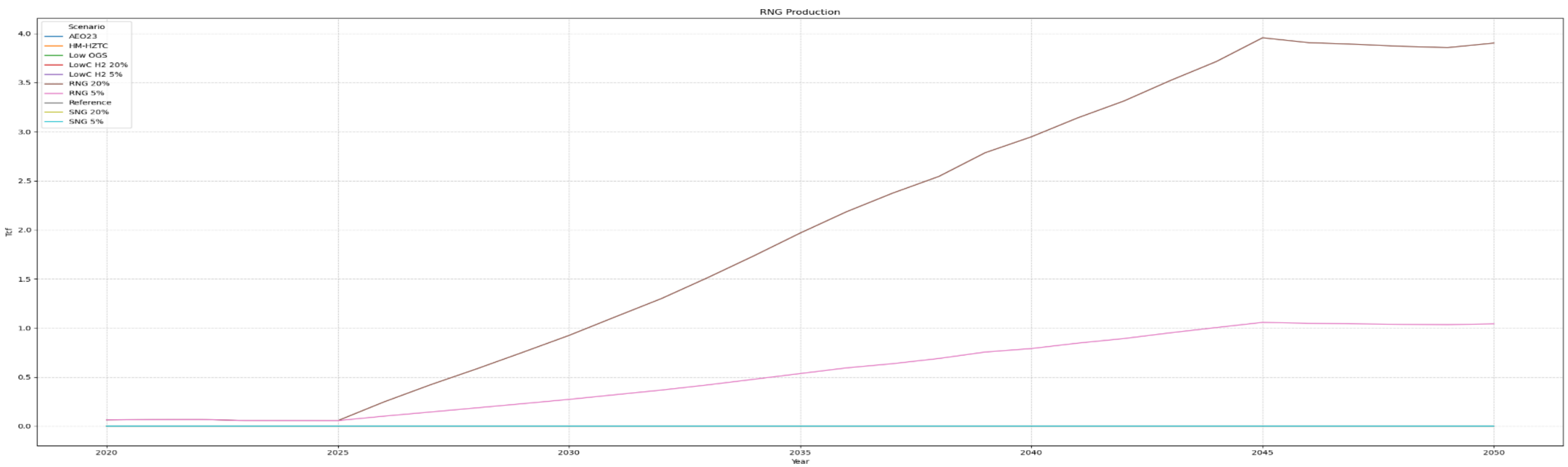

Figure 25. RNG production

RNG Delivered Prices

RNG prices benefit overall from the assumption of freely available MSW. These prices are still higher than other competing technologies for H_2 production (**Figure 26**).

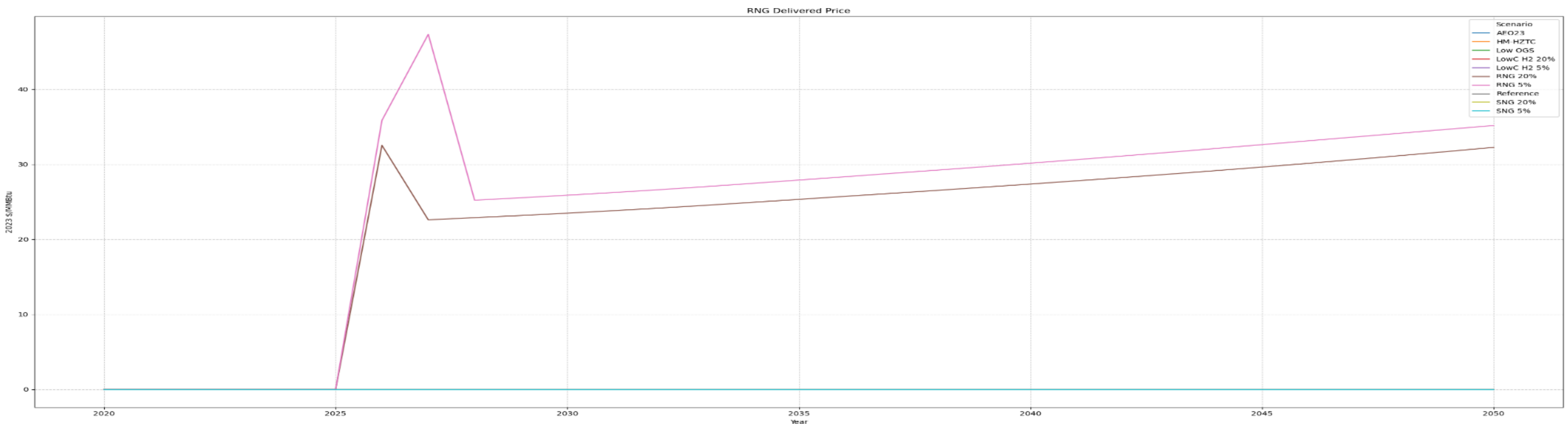

Figure 26. RNG delivered prices

SNG Production

SNG production is only present in the SNG blending cases and scales with the percentage of blending. In the 20% blending case, additional SNG is needed due to higher overall demand for NG in the power sector (**Figure 27**).

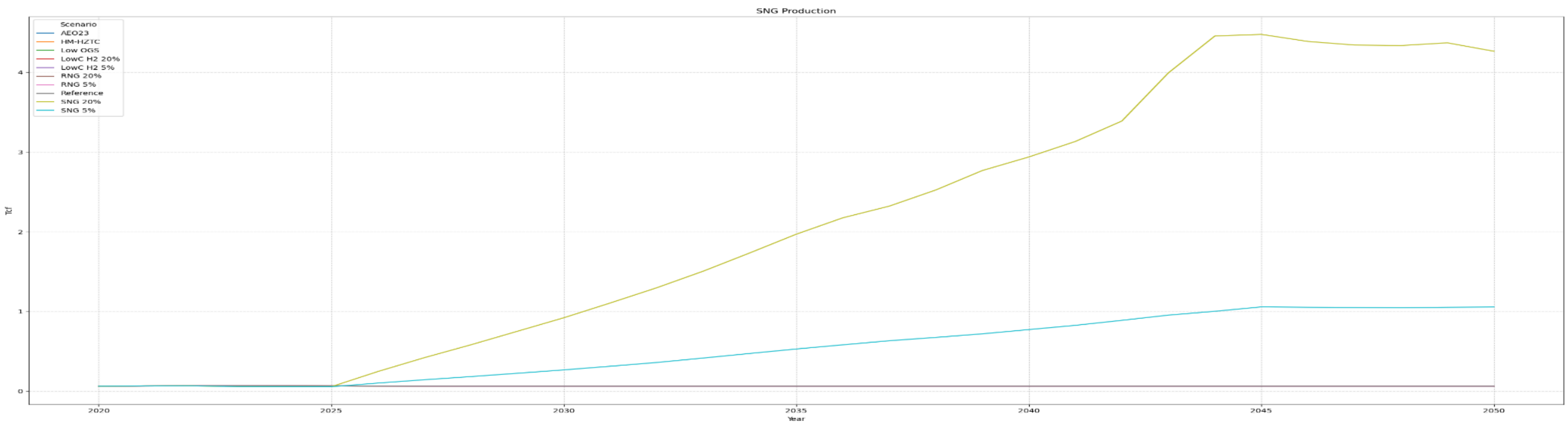

Figure 27. SNG production

SNG Delivered Prices

SNG prices scale rapidly with increased blending due to higher costs of H_2 from electrolysis, CO_2 capture costs from increasingly expensive point sources, and related CO_2 transport costs (**Figure 28**).

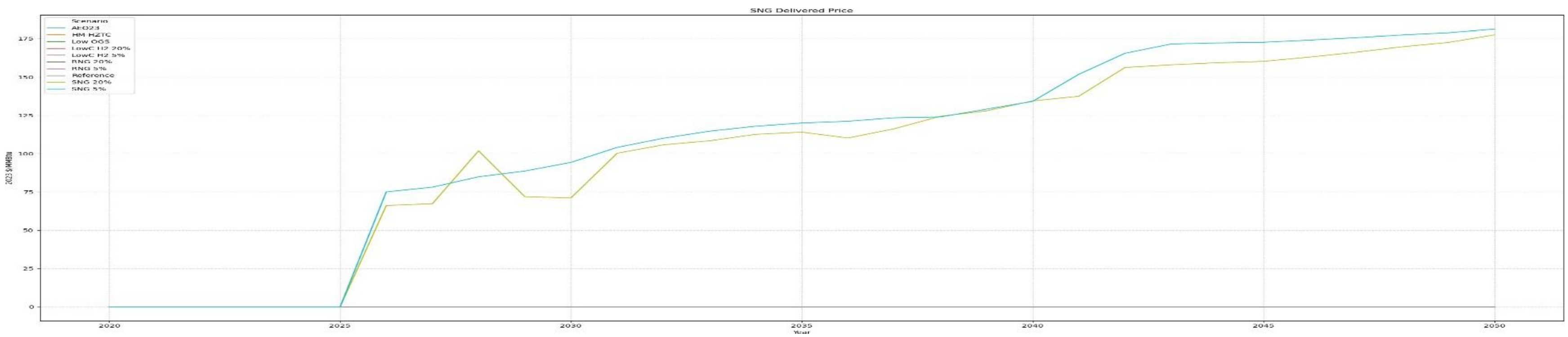

Figure 28. SNG delivered prices