# Low Carbon Fuels in Net-Zero Energy Systems

## White Paper

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EVOLVED ENERGY RESEARCH

## ABOUT THIS REPORT

Environmental Defense Fund commissioned Evolved Energy Research to advance understanding of how low carbon fuels could play a role in achieving net-zero greenhouse gas emissions in the U.S. by 2050. The Bernard and Anne Spitzer Charitable Trust provided financial support for this study.

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## ABOUT EVOLVED ENERGY RESEARCH

Evolved Energy Research (EER) is a research and consulting firm focused on questions posed by transformation of the energy economy. Their consulting work and insight, supported by complex technical analyses of energy systems, are designed to support strategic decision-making for policymakers, stakeholders, utilities, investors, and technology companies.

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# Executive Summary

## Background

The U.S. and international community consistently find that energy efficiency, clean electricity, and electrification are essential and urgent "pillars" of reducing greenhouse gas emissions. However, many recent studies also suggest that deep decarbonization of the energy system by mid-century could require the development and deployment of low-carbon alternatives to traditional fossil fuels, to be used in sectors where clean electricity and electrification cannot fully mitigate emissions. Some of these alternatives to fossil fuels, such as biofuels or hydrogen, are commercially available today, but are not produced or used in a low- or zero-emissions manner. In other words, pathways for the production and use of low-carbon fuels remain nascent and their role in deep decarbonization is relatively understudied.

Environmental Defense Fund (EDF) commissioned Evolved Energy Research to advance understanding of low-carbon fuels' role in the U.S. achieving net-zero GHG emissions by 2050 (on a $CO_2e$ basis). This study sets out to provide that understanding by answering key questions: after aggressive pursuit of efficiency, clean electricity, and electrification, what quantity of low-carbon fuels may still be required? What sectors are most suitable for low-carbon fuels? When are products such as hydrogen and biomass used directly, and when are they feedstocks to other fuels? How sensitive are outcomes to alternative assumptions?

## Approach

The analytical approach for this study is based on our EnergyPATHWAYS and Regional Investment and Operations (RIO) models and exactly matches the approach utilized in the companion *Carbon Management in Net-Zero Energy Systems* white paper. The focus of our analysis includes a set of fuels that are typically referred to as "low carbon fuels" due to reduced emissions impacts relative to conventional fuels. This includes a series of specific fuel types derived from clean electricity, sustainable biomass feedstocks, and fossil fuels with carbon capture. These fall in five categories: (1) hydrogen; (2) ammonia; (3) methane; (4) liquid hydrocarbons; and (5) heavy hydrocarbons. We identify their cost-optimal deployment across sixteen U.S. regions to achieve deep emissions reductions.

We construct a Core Net Zero (CNZ) scenario where the U.S. economy achieves net-zero GHG emissions by 2050 at least-cost using baseline energy technology cost and resource availability assumptions. This baseline provides a starting point to compare against a range of modeled uncertainties that could materially affect low-carbon fuel production and use. We explored alternative: fossil fuel costs; geologic sequestration cost and potential; biomass cost and potential; renewables cost and potential; electrolysis costs; and zero-electric vehicle costs and fuel delivery costs.

Our base assumption for achieving net-zero GHG emissions by 2050 is: (a) modeled energy and industry (E&I) $CO_2$ decreases to 0.0 Gt; and (b) the combination of non-$CO_2$ emissions and the land sink sum to zero using carbon dioxide equivalents with GWP100 (a common simplification for economy-wide net zero analyses). Since the trajectories for non-$CO_2$ mitigation and lank sink enhancement are both highly uncertain and affect the need for carbon management in the energy system to maintain net-zero GHG emissions, we further modeled 2050 E&I $CO_2$ targets of -0.5 Gt and 0.5 Gt.

However, it is becoming increasingly clear that short-lived non-$CO_2$ gases, such as methane, are disproportionately responsible for global warming impacts on shorter timeframes. This suggests that non-$CO_2$ gases are both a great liability to net-zero objectives (because they cause warming) and a great opportunity (because mitigation of their production and leakage presents an efficient pathway to reduce warming). This caveat emphasizes the importance of research we are currently undertaking to develop improved methods that can adequately consider the climate impacts of all GHGs over multiple timescales.

## Key findings

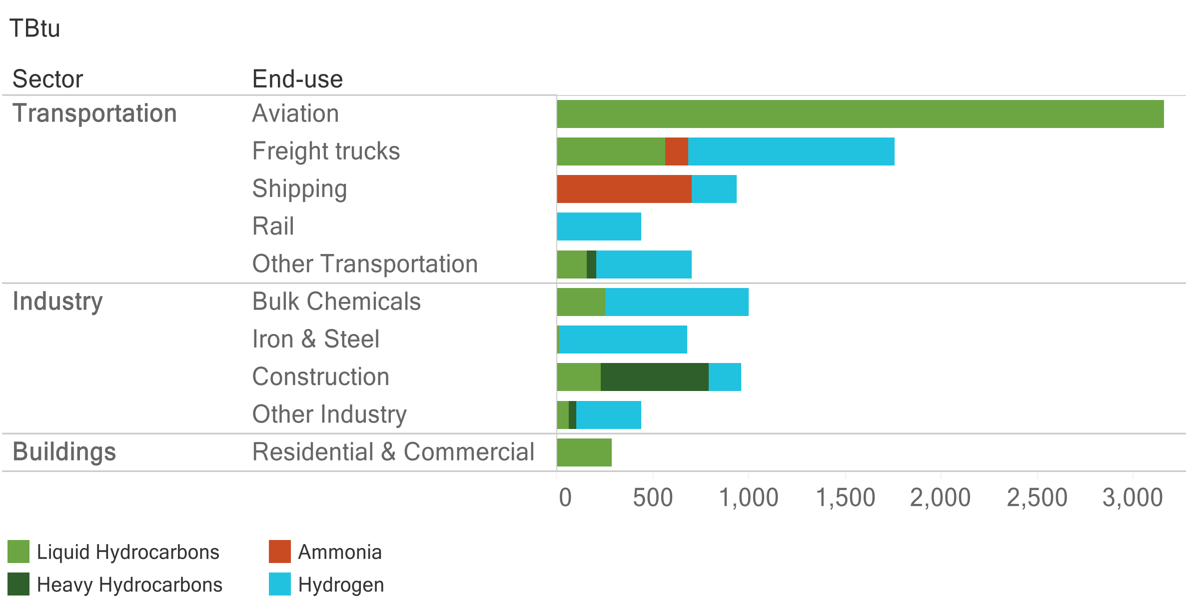
### Low carbon fuel consumption in 2050 is significant, yet a fraction of current fossil fuel use

In the Core Net-Zero scenario, low-carbon fuel use grows from under 0.8 quadrillion BTUs ("quads") in 2030 to 10.3 quads in 2050, equivalent to less than 15% of current U.S. fossil fuel consumption (~80 quads). This demand for combustible fuels remains relatively low due to high uptake of efficiency and end-use electrification across the economy. Low-carbon fuels play the important role of filling residual fuel needs but are deployed in moderation due to their cost premium compared to demand reduction measures, electrification, and continued fossil fuel use.

### Low carbon fuels are critical for decarbonizing hard-to-electrify sectors

Given the importance of electrification in any path to net-zero greenhouse gas emissions, low-carbon fuels are most likely to be critical in sectors where electrification is challenging due to thermal needs, energy density, capital costs, logistics, and/or delivery costs. However, these sectors are highly differentiated, and the analysis finds a diverse mix of low-carbon fuels are deployed to meet net-zero. By 2050, these include direct use of hydrogen (40%) and ammonia (8%), as well as alternative liquid (46%) and heavy hydrocarbons (6%). Uptake is highly contingent on the characteristics of the end-use sector and availability of alternatives; for instance, heavy industry is compatible with direct use of hydrogen, aviation relies on "drop-in" liquid hydrocarbons, and buildings and light-duty vehicles have ample opportunities for electrification and therefore minimal low-carbon fuel use. These outcomes reflect current expectations of technological availability and anticipated progress, but innovation could certainly alter the picture by 2050.

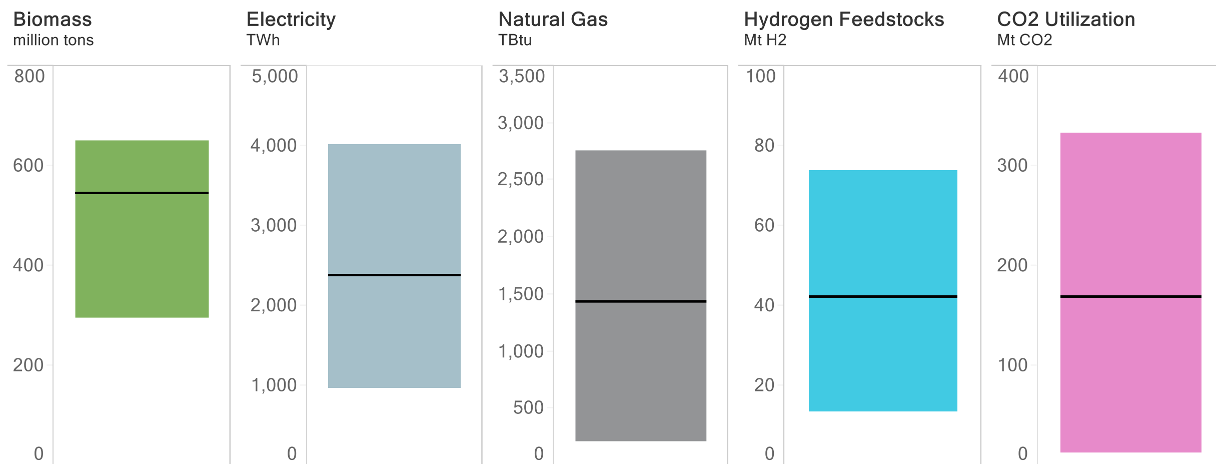
**End Uses for Low Carbon Fuels in 2050 (Core Net-Zero scenario)**




### Low-carbon fuels require significant resources, but innovation can help

Production of low-carbon fuels will require substantial resources. Energy and feedstock needs vary significantly across scenarios based on resource availability, resource costs, and other factors that favor certain fuel production pathways. By 2050 under the Core Net-Zero scenario, the U.S. consumes in the production of low-carbon fuels: more than 500 million tons of biomass (roughly half of maximum potential), 2,400 TWh of clean electricity for hydrogen electrolysis (equivalent to 60% of current electricity consumption), 170 million tons of captured $CO_2$ (3% of current anthropogenic emissions), and 1.5 TBtu of natural gas (5% of current consumption). The scale of these demands highlights the importance of innovation and planning to improve resource availability and cost. Most notably, investment in rapid deployment of mature clean electricity technologies (wind and solar) as well as innovative production techniques (electrolysis) can significantly reduce resource needs. At the same time, it will be important for the United States to develop sustainable supply chains for biofuels and carbon management.

**Resources for Low Carbon Fuel Production in 2050 with Modeled Uncertainties**




Note: range reflects modeled uncertainties and line represents baseline projection (Core Net Zero scenario).

### "Green" hydrogen is a key fuel source for net-zero – if environmental safeguards are in place

By 2050, hydrogen is involved in about 70 percent of low-carbon fuels, either through direct hydrogen use (industry, freight) or as a feedstock to synthetic fuel or ammonia production. Low-carbon hydrogen produced with fossil fuels with carbon capture ("blue" hydrogen) primarily plays a near-term role prior to reduction in the cost of electrolysis ("green" hydrogen). Long-term, though, electrolysis is the predominant hydrogen production pathway, as it is complementary to other features of a deeply decarbonized energy system, namely widespread and cheap renewables. The Department of Energy's recently-announced Hydrogen Shot to achieve $1/kg for clean hydrogen by 2030, if achieved, would double hydrogen production long term, boosting uptake of synthetic fuels derived from hydrogen and $CO_2$ and reducing demand for biomass.

This modeling study does not explicitly characterize potential non-$CO_2$ emissions associated with widespread hydrogen use, including upstream methane leakage in the case of blue hydrogen and potentially significant indirect greenhouse gas effects from the leakage of hydrogen itself. The significant role of hydrogen in a net-zero energy system raises the importance of preemptively addressing these emissions. In the Core Net-Zero scenario, roughly three-quarters of hydrogen is used in stationary applications (industry and fuel conversion plants), which may improve the ability to mitigate emissions compared to diffuse applications (e.g., buildings). Future analysis will seek to identify the possible scale of this challenge.

# Background

Realizing net-zero greenhouse gas (GHG) emissions by 2050 requires contributions across all sectors of the economy. In the energy system, all pathways to net-zero rest on four pillars: (1) electricity decarbonization; (2) energy efficiency; (3) end-use electrification; and (4) carbon management. Taken together, these strategies transform the energy system and steeply reduce $CO_2$ emissions. However, in sectors where direct electrification may be too costly or impractical, low carbon fuels are a promising option to close the emissions gap.

Low carbon fuels are derived from clean electricity resources, sustainable biomass feedstocks, and natural gas with carbon capture, and they have the potential to replace fossil fuel use in 'hard-to-abate' sectors such as long-distance transportation and bulk chemical feedstocks. For example, hydrocarbon demand in aviation can be met by shifting away from fossil jet fuel to "drop-in" synthetic biomass- or electric-derived fuel, while shipping could decarbonize by switching from fossil fuel oil to lower-carbon hydrogen or ammonia.

However, the ultimate demand and supply of low carbon fuels to meet net-zero by mid-century is characterized by considerable uncertainty. For instance, multiple solutions for decarbonizing freight trucks are possible, including synthetic fuels, hydrogen, ammonia and electricity, and vehicle choice over time depends on uncertain trajectories for factors such as lithium-ion costs and hydrogen delivery costs. Supply-side uncertainty ranges from how clean hydrogen will be produced (e.g., green versus blue) and competition for captured $CO_2$ between utilization for fuel production and geologic sequestration.

All of the energy sources underpinning low carbon fuel production have limitations: biomass is constrained by sustainable feedstock availability; renewable electricity has significant land use requirements; and natural gas with carbon capture is constrained by geologic sequestration potential and undercut by upstream methane leaks. Low carbon fuels are also characterized by long and complex production chains where technology costs are rapidly evolving (e.g., synthetic electric fuels require renewable electricity generation, hydrogen feedstocks and captured $CO_2$).

Against this backdrop, the goal of this white paper is to explore the role of low carbon fuels in achieving net-zero GHG emissions in the U.S. We modeled multiple low carbon fuel routes across a broad range of uncertainties to address the following key questions:

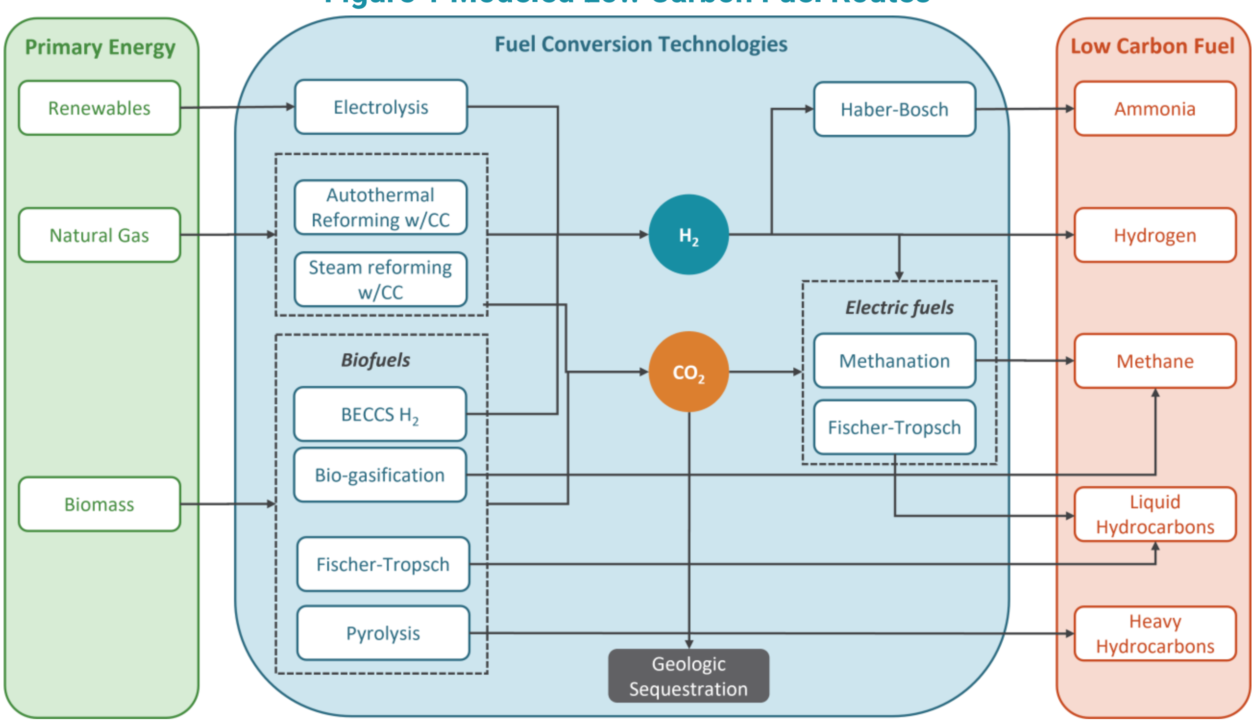
- Where are low carbon fuels used and how much is needed to achieve net-zero?
- Which fuel types are competitive across alternative circumstances?
- What infrastructure is needed to support production and where is it located?
- How much do they cost and what are the main drivers?
- What is hydrogen's role as a fuel and feedstock in a decarbonized energy system?

# Approach and Assumptions

## Scope of Low Carbon Fuels

We modeled multiple routes for low carbon fuel production, as shown in Figure 1. Hydrogen production technologies include: (a) "blue" hydrogen from steam methane reforming and autothermal reforming with carbon capture; and (b) "green" hydrogen from electrolysis and biomass gasification with carbon capture. Hydrogen can be directly used as a fuel in equipment such as fuel cell vehicles or boilers. Alternatively, hydrogen can indirectly serve as a feedstock to produce ammonia (via Haber-Bosch) or combined with captured $CO_2$ to produce synthetic electric fuels (methane or liquid hydrocarbons). Biomass feedstocks are highly flexible and can be converted into alternative fuel types, and bio-refineries with carbon capture can further provide negative emissions for $CO_2$ utilization or storage. Low carbon gasoline fuel (e.g., cellulosic ethanol) is not a focus of this analysis since the economic case for battery electric vehicle adoption in light-duty vehicles is becoming increasingly concrete, and we assume rapid light-duty vehicle electrification that results in gasoline fuel demand falling by 98% from today to 2050.

**Figure 1 Modeled Low Carbon Fuel Routes**



# Modeling Approach

We use our EnergyPATHWAYS (EP) and Regional Investment and Operations (RIO) models to evaluate low carbon fuel supply and demand in the U.S. energy system. We use EP to develop a bottom-up projection of final energy demand for end-uses across the economy excluding long-distance transportation. This projection is based on user-defined (exogenous) energy efficiency and fuel switching levers. Next, we use RIO to identify least-cost (endogenous) technology deployment for: (a) long-distance transportation end-uses; and (b) energy supply infrastructure (i.e., electricity; fuels; carbon management).

Vehicle and fuel options for long-distance transportation end-uses are summarized in Table 1. For freight trucks (medium- and heavy-duty vehicles), direct electrification competes with fuel cell vehicles that can use hydrogen or ammonia, while non-electric delivered fuel options are available for aviation, rail and shipping. We limit the use of ammonia as a low carbon fuel in freight trucks and shipping due to uncertainty about technical challenges before large-scale adoption is practical.[1] For all end-uses, our least-cost framework means that continued consumption of fossil-derived liquid hydrocarbons only persists if capturing and storing $CO_2$ from the atmosphere (e.g., direct air capture) to address residual emissions is more economic than low carbon fuel use.

**Table 1 Long-distance Transportation Options**

| End-use | Vehicle and Fuel Options |
|---|---|
| **Freight Trucks** | • Internal combustion engine (liquid hydrocarbons)<br>• Battery electric vehicle<br>• Hydrogen fuel cell vehicle<br>• Ammonia fuel cell vehicle (up to 25% of vehicles) |
| **Aviation** | • Liquid hydrocarbons |
| **Rail** | • Liquid hydrocarbons<br>• Hydrogen |
| **Shipping** | • Liquid hydrocarbons<br>• Hydrogen<br>• Ammonia (up to 75% of energy demand) |

[1] See Erdemir and Dincer (2020) for a review of ammonia's technical challenges and possible solutions.

We represent the U.S. energy system across 16 geographic regions that reflect: (a) diverse resource endowments, such as renewable resource, biomass feedstock and geologic sequestration availability; and (b) variations in energy consumption due to economic structure and climate.[2] Regional low carbon fuel supply and demand outcomes are strongly influenced by these factors.

The portfolio of low carbon fuels to achieve net-zero GHG emissions depends on uncertain trajectories for multiple factors, such as biomass feedstock availability, green hydrogen production costs, and infrastructure costs for zero emission vehicles. Given this uncertainty, we modeled scenarios in the following manner. First, we construct a Core Net Zero (CNZ) scenario reflecting our base assumptions and this is the starting point used to compare all other sensitivities against. Next, we implement multiple sensitivities off the CNZ scenario that reflect uncertainties that could affect low carbon fuel supply and demand. We explore a range of alternative assumptions for factors such as fossil fuel prices; resource potential (biomass, renewables, geologic sequestration); zero emission vehicle and energy technology costs; and emissions reduction targets for energy and industrial $CO_2$. Finally, we evaluate a case study where DOE's Hydrogen Shot target of $1/kg by 2030 is achieved and discuss its broad implications.

# Key Assumptions

The base assumptions for the CNZ scenario are consistent with our recent carbon management white paper, and they are applied across the analysis unless specified otherwise.[3] All scenarios achieve GHG emission reductions of 50% below 2005 levels by 2030 and net-zero by 2050, while meeting energy services projected from the U.S. Department of Energy's (DOE) Annual Energy Outlook (AEO). We use publicly available data from U.S. government agencies or laboratories to characterize fuel costs and technology costs and performance. Fossil fuel costs track the AEO 2021 Reference Case, while renewable technology cost and performance trajectories are from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) 2020

[2] This topography has been utilized in a variety of deep decarbonization pathways analyses. For example, see Haley et al. (2018) and Larson et al. (2020).

[3] See Kwok et al. (2022).

Moderate Scenario. We rely on our experience modeling net-zero U.S. energy systems to develop assumptions for end-use efficiency and fuel switching to electricity and hydrogen-based fuels.

We considered seven areas of uncertainty that could have a material impact on low carbon fuel outcomes. Table 2 summarizes these uncertainties and our rationale for evaluating their impact. Although these uncertainties were selected to aid understanding of which factors affect low carbon fuels, they do not capture every possible circumstance.

**Table 2 Area of Uncertainty Addressed through Sensitivity Analysis**

| Uncertainty | Rationale |
|---|---|
| **Fossil Fuel** | • Fossil fuel prices reflect the avoided cost for low carbon fuels and provide the economic signal for resource allocation[4]<br>• The relative cost of natural gas and petroleum-based products affects fuel allocation (e.g., limited biomass feedstocks allocated to synthetic liquids or gaseous fuel production)<br>• Natural gas is a large cost component of blue hydrogen production |
| **Sequestration** | • CO2 storage costs and availability impact fuel production with carbon capture (i.e., BECCS and blue hydrogen) |
| **Biomass** | • Biomass availability and cost affects the economics of biofuels production and competition with electric-based fuels |
| **Renewables** | • Renewable resource costs and potential are strong determinants of electrolytic hydrogen's cost and usage in a net-zero energy system<br>• Cheaper renewables direct more captured CO2 towards utilization, while more expensive renewables favor CO2 storage |
| **Electrolysis** | • Technology cost trajectory is highly uncertain<br>• Like renewable resource costs, the cost of an electrolyzer affects the magnitude of green hydrogen's role (e.g., direct use in transportation, indirect use as a feedstock for synthetic fuels, etc.) |
| **Zero Emission Vehicle** | • Relative cost of battery electric trucks against alternatives impact both the demand for low carbon fuels<br>• Vehicle costs and delivery costs (e.g., electric charging infrastructure; hydrogen delivery infrastructure) are important drivers |
| **Emissions** | • Emissions reduction target for energy and industrial $CO_2$ broadly determines the need for low carbon fuels to meet net-zero GHG<br>• Uncertainty about non-$CO_2$ mitigation and land sink enhancement means that more or less E&I CO2 reductions may be required |

[4] Does not include the cost of criteria pollutant impacts.

We developed low and high values relative to the base assumption to understand the range of outcomes for each area of uncertainty, as summarized in Table 3. Some factors are controllable or partially controllable through policy, such as R&D funding for energy technologies that reduce their cost, while others are outside of policymaker's control. A detailed description of assumptions and data sources can be found in the technical appendix to this white paper.

**Table 3 Summary of Base and Sensitivity Assumptions in 2050**

| Category | Sub-Category | Indicative Base Value | Sensitivity Range |
|---|---|---|---|
| **Fossil Fuels** | Crude Oil Price ($/barrel) | 95 | 48 to 173 |
| | Henry Hub Natural Gas Price ($/MMBtu) | 3.7 | 2.7 to 6.5 |
| **Sequestration** | Potential ($GtCO_2$/yr) | 1.9 | 1.2 to 3.0 |
| | Cost ($/$tCO_2$) | 25 to 70 | +/-20 |
| **Biomass** | Potential (billion tons) | 0.75 | 0.31 to 1.36 |
| | Cost ($/ton) | 80 to 150 | +/-50 |
| **Renewables** | Potential in the lower-48 states (TW) | Utility solar: 3.6<br>Onshore wind: 5.8 | Utility solar: 1.2 to 6.0<br>Onshore wind: 3.9 to 7.8 |
| | Cost ($/kW-ac) | Utility solar: 700<br>Onshore wind: 1,050 | Utility solar: 530 to 860<br>Onshore wind: 670 to 1,260 |
| **Electrolysis** | Cost ($/kW-e) | 250 | 100 to 400 |
| **Zero Emission Vehicle** | BEV cost ($000/vehicle) | MDV: 90.3<br>HDV: 187.5 | MDV: 85.3 to 95.3<br>HDV: 160.3 to 214.8 |
| | HFCV cost ($000/vehicle) | MDV: 91.0<br>HDV: 152.2 | MDV: 84.5 to 97.0<br>HDV: 139.3 to 165.0 |
| | BEV infrastructure cost ($000/vehicle) | MDV: 27.6<br>HDV: 56.9 | MDV: 9.2 to 34.6<br>HDV: 35.3 to 136.7 |
| | $H_2$ delivery cost ($/gge) | 1.5 | 1.0 to 2.0 |
| **Emissions** | E&I $CO_2$ target (Gt $CO_2$) | 0.0 | -0.5 to +0.5 |

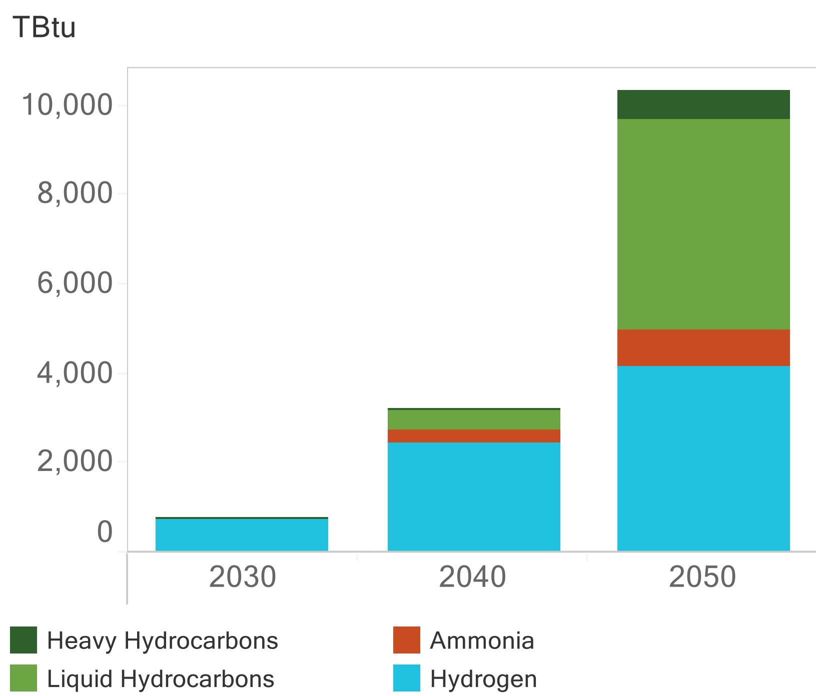
# Role of Low Carbon Fuels

In this section, we summarize the role of low carbon fuels for the CNZ scenario and the sensitivity of these results to a range of uncertainties. We report technology-specific results for each fuel type and regional infrastructure supporting their production. We also provide indicative production and delivery cost estimates for low carbon fuels and compare them against their fossil fuel equivalents. Finally, we discuss the energy system impacts from achieving DOE's recent Hydrogen Shot goal of $1/kg by 2030.

## Overview of the Core Net Zero Scenario

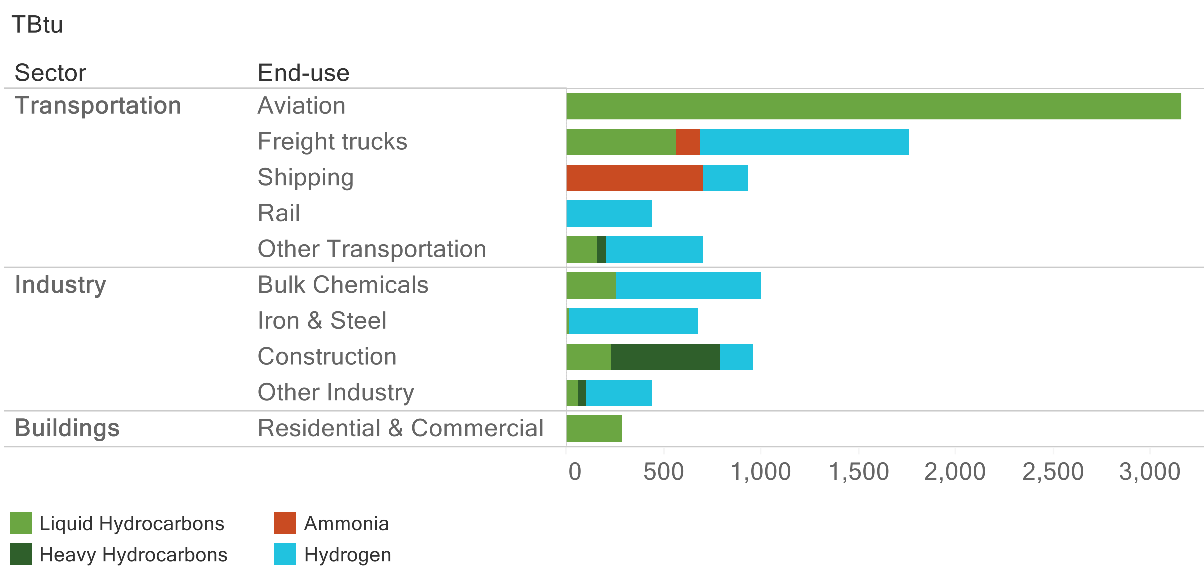
Consumption of low carbon fuels begins in 2030 with the production of low carbon hydrogen to decarbonize existing uses (e.g., bulk chemicals) and to meet growing transportation sector demand (e.g., freight trucks). After 2030, overall consumption grows rapidly and expands to other fuel types as the net-zero target necessitates decarbonization across all sectors. By mid-century, liquid hydrocarbons and hydrogen are the predominant low carbon fuels consumed.

**Figure 2 Low Carbon Fuel Consumption**



By mid-century, low carbon fuel consumption is concentrated in the transportation and industrial sectors (Figure 3). Long-distance transportation (aviation, freight, rail, shipping) are the largest consuming sectors of low carbon fuels. Aviation relies on liquid hydrocarbon due to dense energy requirements, while freight vehicles that are not electrified use both hydrogen and liquid hydrocarbons at scale. Industry demands significant hydrogen to decarbonize chemicals and iron & steel (e.g., hydrogen-based direct reduced iron). Buildings consume very few low carbon fuels due to the prominence of electrification as a decarbonization strategy and remaining natural gas use is addressed with CCS for economic reasons, which we discuss in detail below.

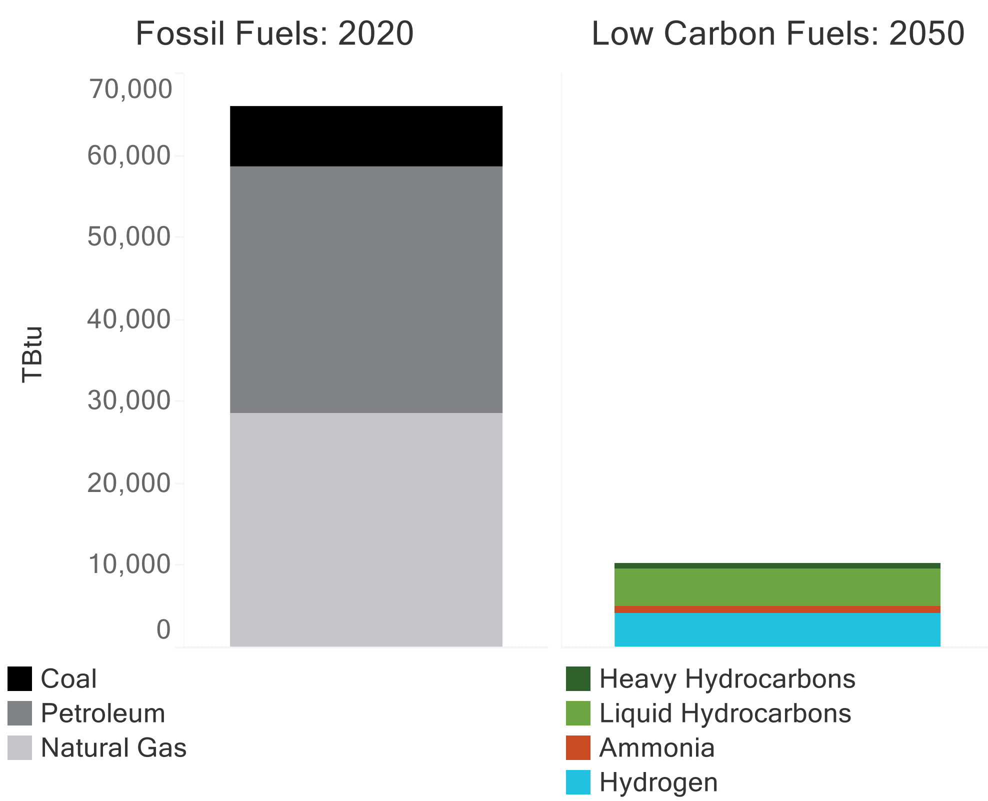
### Figure 3 Consumption by Sector: 2050




Despite the importance of using low carbon fuels in hard-to-abate sectors, consumption by mid-century is small relative to today's fuel use (Figure 4). Fossil fuel consumption in 2020, impacted by lower economic activity from COVID-19, is estimated to be approximately 70 quads, which is down from approximately 80 quads in 2019. In contrast, low carbon fuel consumption in 2050 is about 10 quads or less than 15% of today's fossil demand.

To achieve net-zero at reasonable cost, increased energy efficiency and electrification are essential strategies to first drive down overall energy demand, while low carbon fuel deployment is then needed to further reduce energy sector emissions. As further discussed in section 3.4 below, the cost premium of low carbon fuels relative to fossil fuels means that it is uneconomic to produce them at levels similar to today's fossil fuel use. In addition, biomass, renewable and geologic sequestration resource constraints establish upper bounds on low carbon fuel production that limit widespread use. The implication for companies that currently supply most fossil fuel and plan to transition to low carbon fuels is a future with significantly lower volumes, albeit at higher costs.

**Figure 4 Comparison of Fuel Consumption**

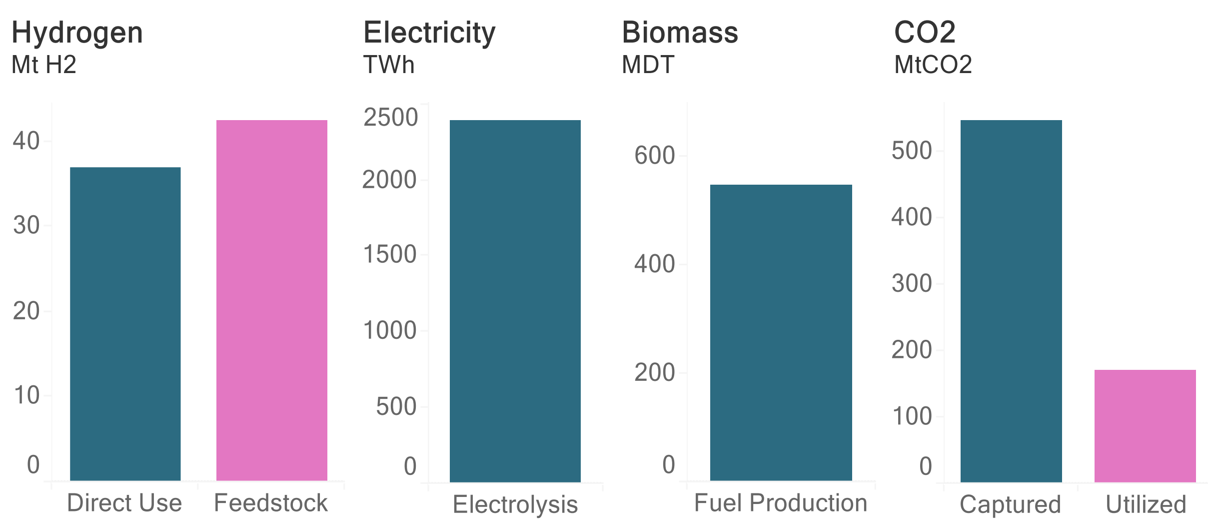



As shown in Figure 5, development of a low carbon fuel supply requires scaling up infrastructure across the energy sector, including a combined effort of expanding mature technologies (e.g., wind and solar), deploying nascent technologies at scale (e.g., electrolysis) and developing new supply chains (biomass and carbon management). Currently, the U.S. produces 10 million metric tons of hydrogen, which is all supplied from unabated steam methane reformation.[5] In the CNZ

[5] https://www.energy.gov/eere/fuelcells/fact-month-may-2018-10-million-metric-tons-hydrogen-produced-annually-united-states

scenario, more than 70 million metric tons are produced by 2050, where approximately half is consumed directly in technologies such as boilers and fuel cell vehicles and the remaining half is used as a feedstock for synthetic electric fuel and ammonia production. Electrolysis is the predominant source of hydrogen produced by mid-century (around two-thirds as shown in Figure 7) and uses approximately 2,400 TWh of clean electricity (equivalent to a 830 GW generation resource with a 33% capacity factor). For context, total wind and solar generation in the U.S. was 370 TWh in 2019. The U.S. already has a large-scale biofuels industry, but this is centered around corn-derived ethanol in gasoline fuel. A net-zero-compliant economy transitions towards advanced biofuels producing primarily liquids and hydrogen. This new industry consumes approximately half of the U.S. biomass potential and primarily consists of bio-refineries equipped with carbon capture (i.e., BECCUS). Captured $CO_2$ is a highly valuable component of the low carbon supply chain, and more than 150 Mt CO2 is utilized to produce liquid hydrocarbons via synthesis with hydrogen[6].

**Figure 5 Low carbon Resource Metrics: 2050, Core Net Zero**




[6] Carbon management is explored in more detail here: [Carbon Management White Paper]

# Low Carbon Fuel Deep-Dives

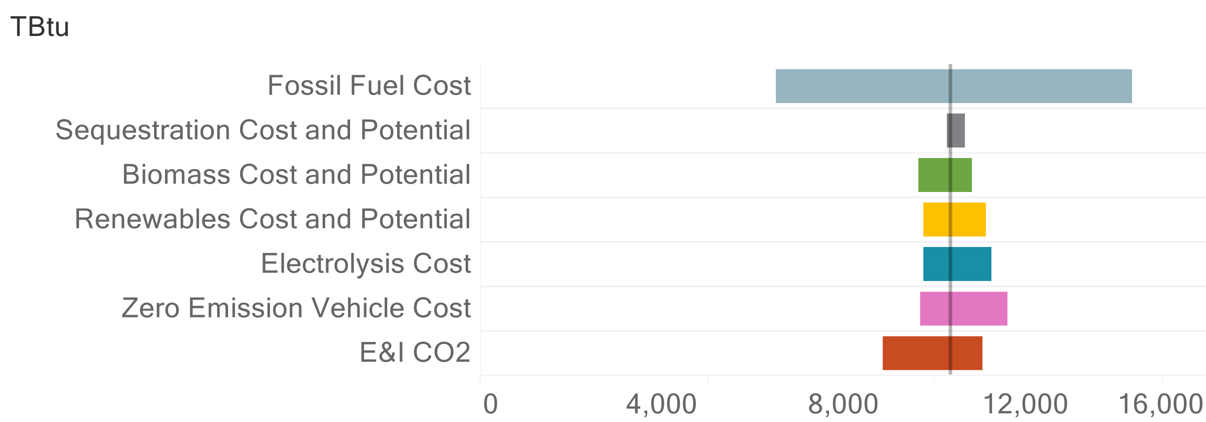
## Overview

Total low carbon fuel consumption in 2050 is relatively flat across the uncertainties considered in this analysis (Figure 6). The most impactful uncertainties where total consumption deviates significantly from the CNZ scenario include petroleum product costs, the E&I $CO_2$ emissions target and BEV vehicle and infrastructure costs. Consumption increases substantially with: (a) higher petroleum product costs, because the avoided fossil fuel cost increases (i.e., the $/MMBtu cost of a low carbon fuel is lower than its refined fossil fuel equivalent); (b) a net negative target for E&I CO2, because residual fossil fuel consumption must either be decarbonized with low carbon fuels or addressed with negative emissions; and (c) higher-than-anticipated battery electric vehicle or infrastructure costs, since this reduces BEV adoption and increases hydrogen and synthetic liquid hydrocarbon use in freight trucks.

Persistently low petroleum product costs reduce low carbon fuel consumption by nearly 40% since it is more economic to continue using fossil diesel and jet fuel in applications such as long-distance transportation and addressing residual emissions with carbon dioxide removal technologies coupled with geologic sequestration. Additional progress to reduce non-CO2 emissions and/or enhance the land sink, which eases the abatement burden on the energy sector, reduces low carbon fuel demand by approximately 20%.

For the other uncertainties where the total consumption is similar to the CNZ scenario, the primary impact of the uncertainties is competition among fuels (e.g., hydrogen versus ammonia) or the supply source for a fuel (e.g., liquid hydrocarbons supplied by synthetic bio- or electric-based technologies). We discuss these dynamics below.

Figure 6 Low carbon Fuel Consumption: 2050 (All Cases)

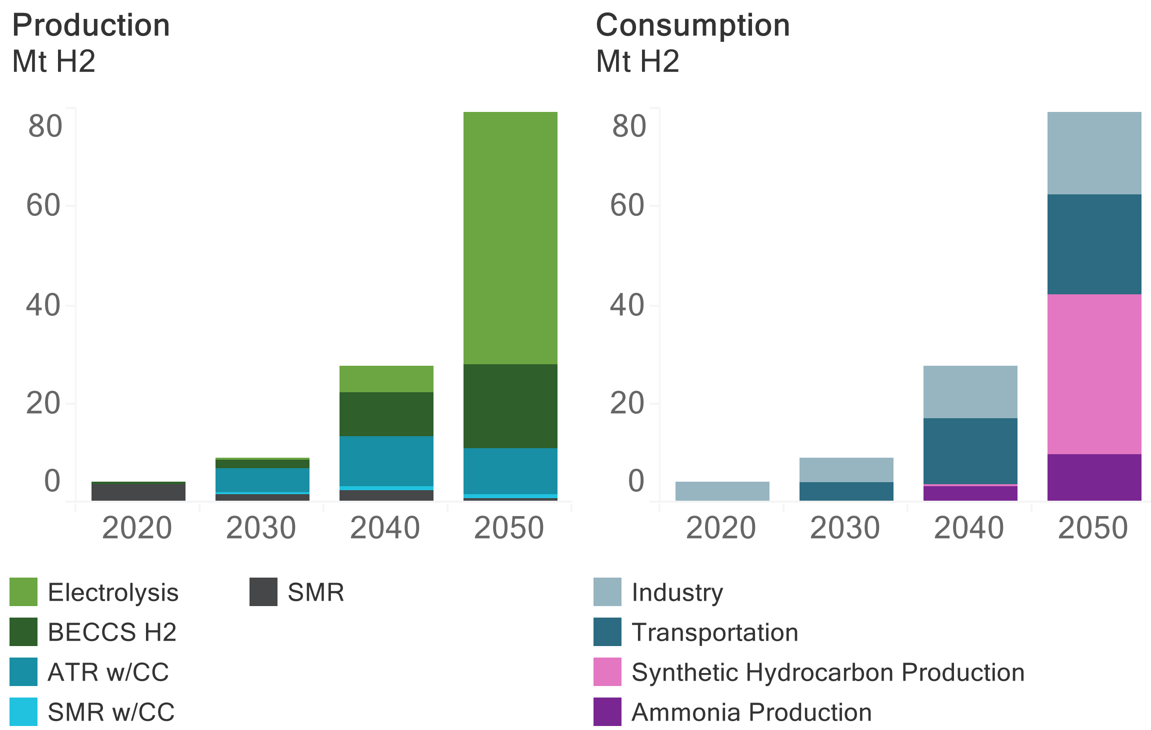



## Hydrogen

Hydrogen is a core component of the low carbon fuel supply chain due to its dual role as a fuel that can be directly consumed or indirectly used as a feedstock in a conversion process. Its importance is highlighted by the fact that 70% of low carbon fuels consumed are directly or indirectly based on hydrogen. Near-term consumption growth is driven by the transportation sector, particularly freight trucks (Figure 7). Transportation demand continues to grow afterwards, but synthetic hydrocarbon and ammonia production facilities outpace direct transportation applications (fuel cells) and consume approximately half of all hydrogen by mid-century. About three-quarters of all hydrogen is consumed by stationary facilities (industrial and fuel conversion plants), which suggests that most hydrogen will be transported short distances or production will be co-located where it's consumed. This has important implications for managing infrastructure costs and risks associated with hydrogen transportation, including possible leakage. We don't model hydrogen's direct use in buildings and the transportation use is limited to shipping or some freight trucks, limiting the need for significant hydrogen delivery networks.

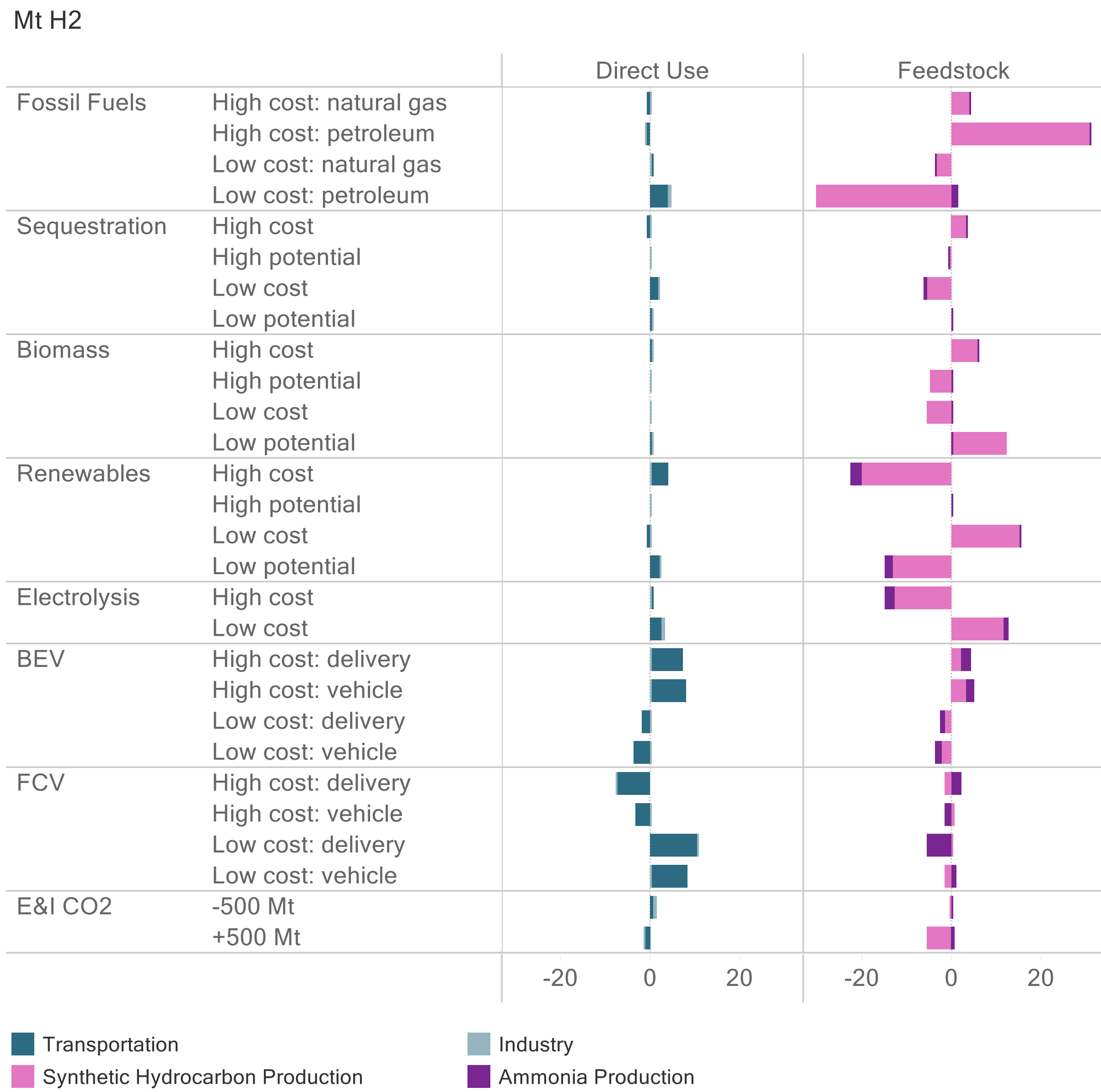
In the near-term, blue and biomass-based hydrogen meets growing demand, while grey (unabated) hydrogen production declines. Electrolysis becomes the principal source of hydrogen production in the long-term as: (a) electrolysis and renewable resource costs decline over time; (b) electrolysis helps balance the electricity system as the weight of variable renewable generation in the mix increases; and (c) blue and BECCUS hydrogen are both constrained by sequestration availability and face competition from other $CO_2$ sources.

**Figure 7 Hydrogen Production and Direct Consumption: Core Net Zero Scenario**




The range of uncertainties considered in Figure 8 highlights how the application of hydrogen (direct use or feedstock consumption) is affected by various factors. We find that variation in the direct use of hydrogen is largely driven by assumed ZEV freight truck and associated delivery infrastructure costs more so than hydrogen production costs. Lower fuel cell vehicle and hydrogen delivery costs (or higher BEV and charging infrastructure costs) incentivize additional use of hydrogen in freight trucks, and vice versa. In contrast, demand for hydrogen as a feedstock is highly sensitive to factors impacting hydrogen production costs, specifically electrolysis and renewable cost trajectories. Petroleum product prices are an even larger determinant of hydrogen feedstock demand since they provide the avoided cost signal for synthetic liquid hydrocarbons. The range of outcomes for hydrogen consumption as a feedstock by 2050 is greater than that for direct use of hydrogen, as there is a much wider array of potential applications for hydrogen-based fuels.

## Figure 8 Hydrogen Demand: Change from Core Net Zero

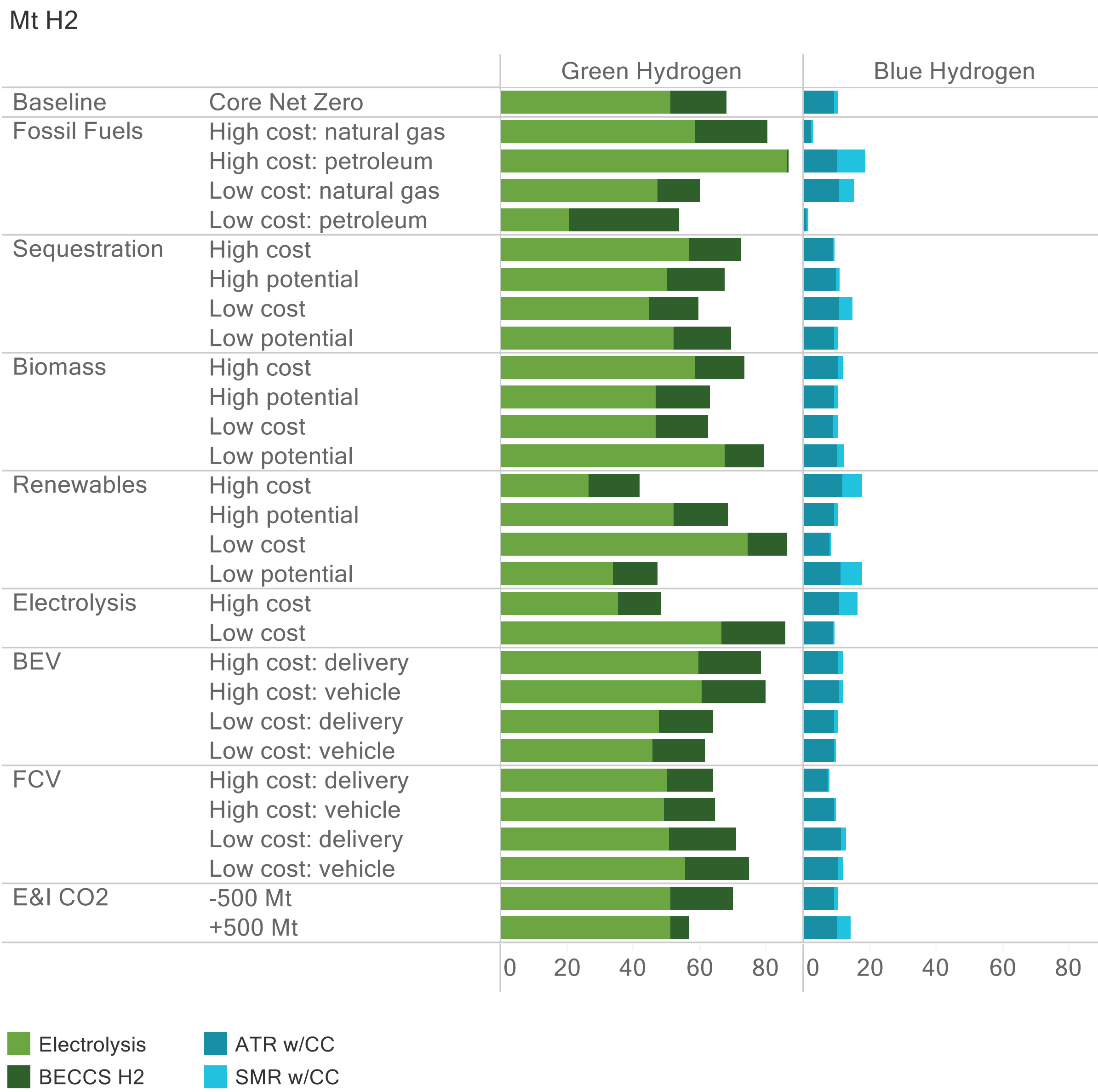



We find that green hydrogen is consistently the predominant source of hydrogen production in the long-run across a range of uncertainties (Figure 9). As discussed in prior analysis, electrolysis demonstrates strong complementarity with other technologies deployed at scale in a net-zero energy system, but its deployment is highly sensitive to renewable cost and potential assumptions.[7] Hydrogen derived from biomass with carbon capture is another important source, but production is constrained by overall biomass feedstock availability, competition with other biofuels technologies and geologic sequestration availability.

Blue hydrogen, even under the most favorable conditions (low-cost natural gas and low-cost CO2 storage), is never more than one-third of total hydrogen production by 2050. As discussed in our carbon management white paper, negative emissions from BECCUS and DAC become more attractive options for addressing any remaining emissions, and fossil-based, carbon-neutral technologies such as blue hydrogen compete for the same geologic storage space. Approximately 500 to 600 MMT of $CO_2$ sequestration would be required by 2050 if all hydrogen demand in the Core Net Zero scenario came from ATR and SMR with carbon capture. However, the technology plays a larger role in the near-term prior to the cost of electrolytic hydrogen falling to economic price points.

[7] See Unlocking Deep Decarbonization: An Innovation Impact Assessment (2021).

**Figure 9 Hydrogen Production**




## Ammonia

Ammonia is a hydrogen-based fuel that has been identified as a promising option to decarbonize long-distance transportation since: (a) it can be used directly used in both internal combustion engines and fuel cells; and (b) it may be able to use existing transportation, storage and distribution infrastructure, which results in lower fuel delivery costs than hydrogen.[8] The Haber Bosch process is the principal method of ammonia production and is an energy intensive process requiring significant volumes of decarbonized hydrogen and nitrogen.

We find that ammonia use in shipping and freight transportation increases when: (a) hydrogen *production* costs decrease (e.g., lower renewable resource and electrolysis costs); and (b) hydrogen *delivery* costs increase. Ammonia consumption decreases when the opposite is realized for hydrogen production and delivery costs. For example, if hydrogen delivery costs can be reduced from $1.5/gge to $1.0/gge, then ammonia use declines by two-thirds. This dynamic is a result of their delivered cost structures: the delivered cost of ammonia is characterized by a very high share of hydrogen feedstock costs and low delivery costs, whereas the delivered cost of hydrogen is roughly split between production and delivery costs.

## Liquid Hydrocarbons

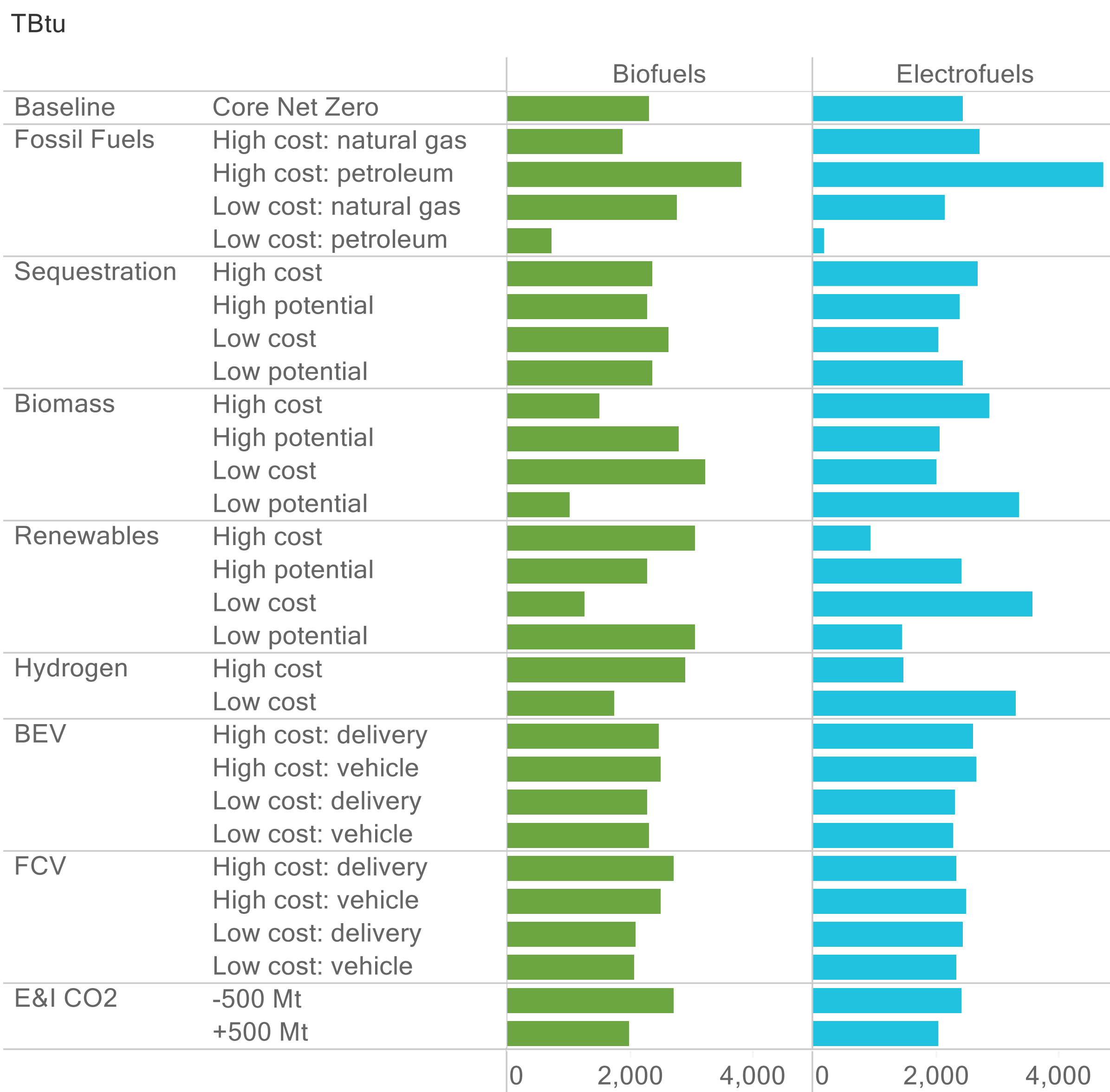
Production of synthetic bio- and electric-derived fuels are an important strategy for decarbonizing refined liquid fuels such as jet fuel used in aviation and diesel fuel consumed in freight transportation and heavy industry. Low carbon liquid hydrocarbons are prioritized over gaseous fuels, because their refined fossil fuel equivalents are both higher cost and more carbon intensive than natural gas. For example, projected fossil diesel and jet fuel costs in 2050 are approximately $20/MMBtu, whereas natural gas is less than $4/MMBtu. These factors, combined with the fact that they are primarily used in hard-to-abate end-uses, results in consistent volumes across a range of uncertainties (4,000-5,000 TBtu). Large deviations in demand only occur when petroleum product costs are persistently low (continue using fossil fuels and offset with sequestration) or high (economic to only use low carbon fuels).

Liquid hydrocarbons are supplied by a combination of bio- and electric-derived synthetic liquids, both using Fischer-Tropsch synthesis. Economic production of liquid biofuels is limited by biomass feedstock supply in each region, whereas liquid electric fuels are constrained by the supply of economic hydrogen and captured $CO_2$. Given the importance of these feedstocks to their overall production cost, variations in supply are most sensitive to the cost and availability of

[8] Ammonia can also be used as an intermediate hydrogen carrier and re-converted back to hydrogen, which we did not considered in this white paper.

biomass resources, renewable resources, geologic sequestration and electrolytic hydrogen production costs. Liquid biofuels production ranges from -50% to +20% compared to the CNZ scenario depending on feedstock availability, and electric liquid fuels range from -60% to +50% depending on renewable costs.

**Figure 10 Liquid Hydrocarbon Supply**

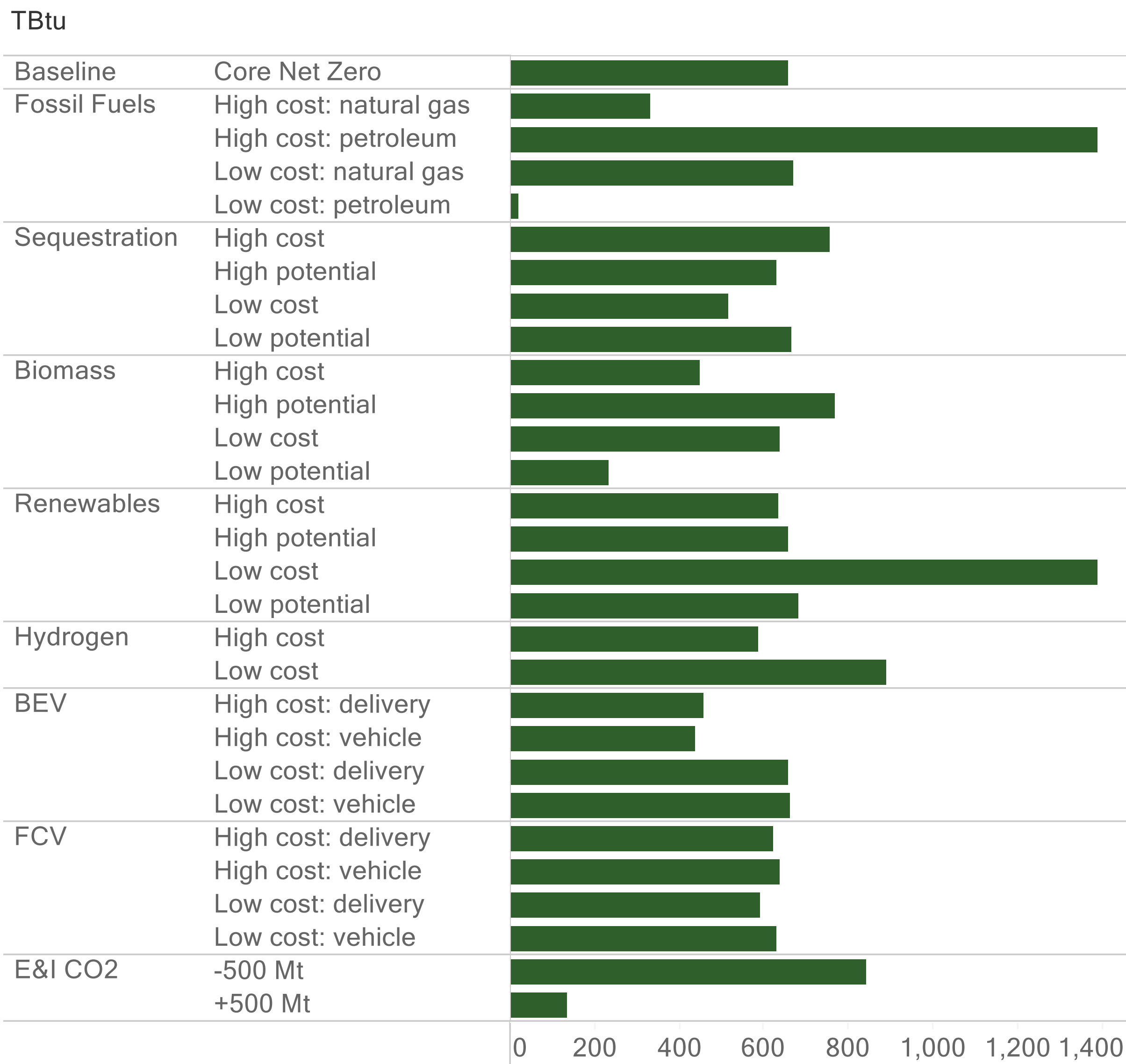


## Heavy Hydrocarbons

Heavy hydrocarbons encompass a wide range of petroleum products excluding high-value refined fuels such as gasoline, diesel and jet fuel. They are consumed across a diverse set of industries, such as asphalt in construction and lubricants in vehicles. Decarbonization options are limited because electrification is not an option and the low carbon fuel must maintain the same properties as petroleum. Pyrolysis is a process that decomposes biomass to produce a bio-oil that can displace crude oil and decarbonized its refined products.

We find that heavy hydrocarbons produced from pyrolysis may be an important “last-mile” low carbon fuel to achieve net-zero, but volumes are highly sensitive to uncertain assumptions (ranging from 0 to 1,400 TBtu). The end-uses that consume heavy hydrocarbons are among the last to be decarbonized on the path to net-zero, because: (a) the petroleum products are low-value (low-cost) relative to high-value (high-cost) refined liquids such as diesel; and (b) pyrolysis is limited by biomass availability and competes with other bio-refinery technologies that displace more expensive fuels.

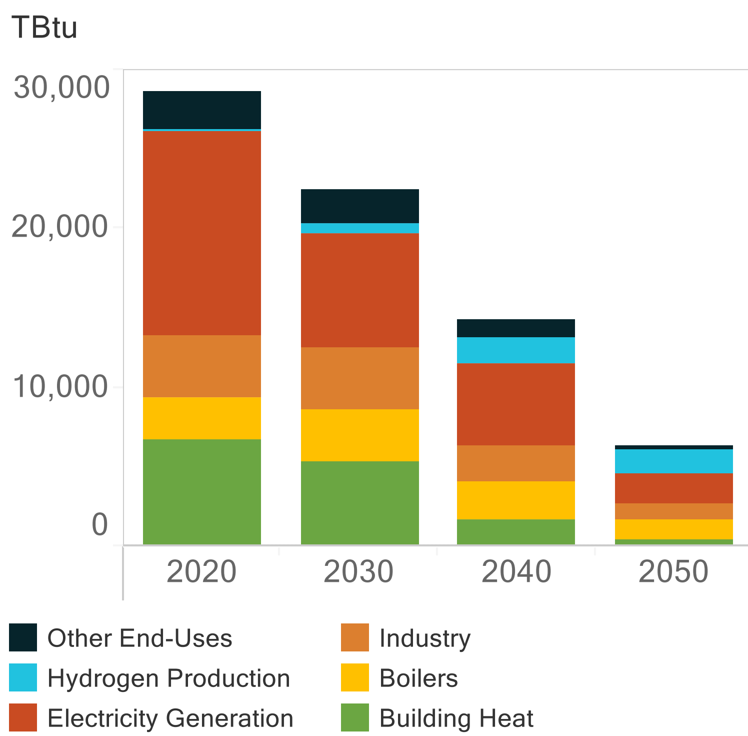
**Figure 11 Heavy Hydrocarbons Consumption**




## Methane

A finding of this study is that the production of low carbon pipeline gas fuel (e.g., renewable natural gas) is not significant and a lower-priority than liquid and heavy hydrocarbons. As shown in Figure 12, pipeline gas is consumed across a wide range of end-uses, including heat in buildings and industry, electricity generation and hydrogen production. Pipeline gas use falls significantly (approximately 75% below 2020 levels by 2050) because of building electrification and growing renewable electricity generation, but natural gas remains the largest source of gross energy $CO_2$ emissions. The remaining fuel demand is not decarbonized with low carbon fuels such as bio-gasification and synthetic natural gas from methanation, because the cost of doing so far exceeds the combined cost of natural gas and negative emissions. The ongoing presence of pipeline gas consumption in 2050 raises important implications for policymakers focused on addressing methane emissions from gas distribution; significant methane leak mitigation efforts will be needed through mid-century.

**Figure 12 Pipeline Gas Consumption: Core Net Zero**



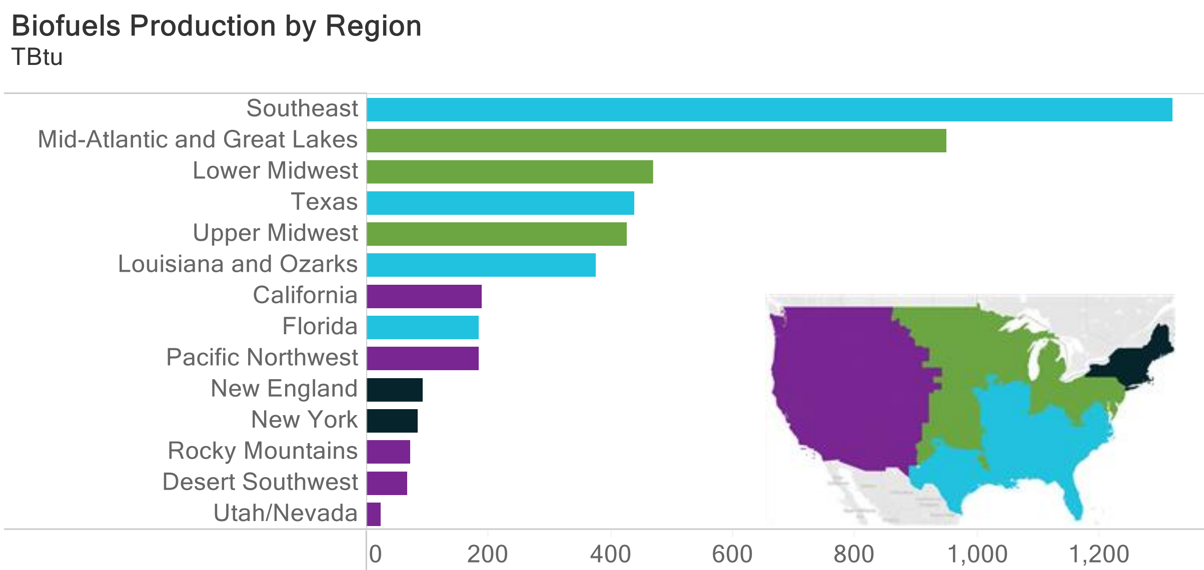

# Regional Infrastructure Implications

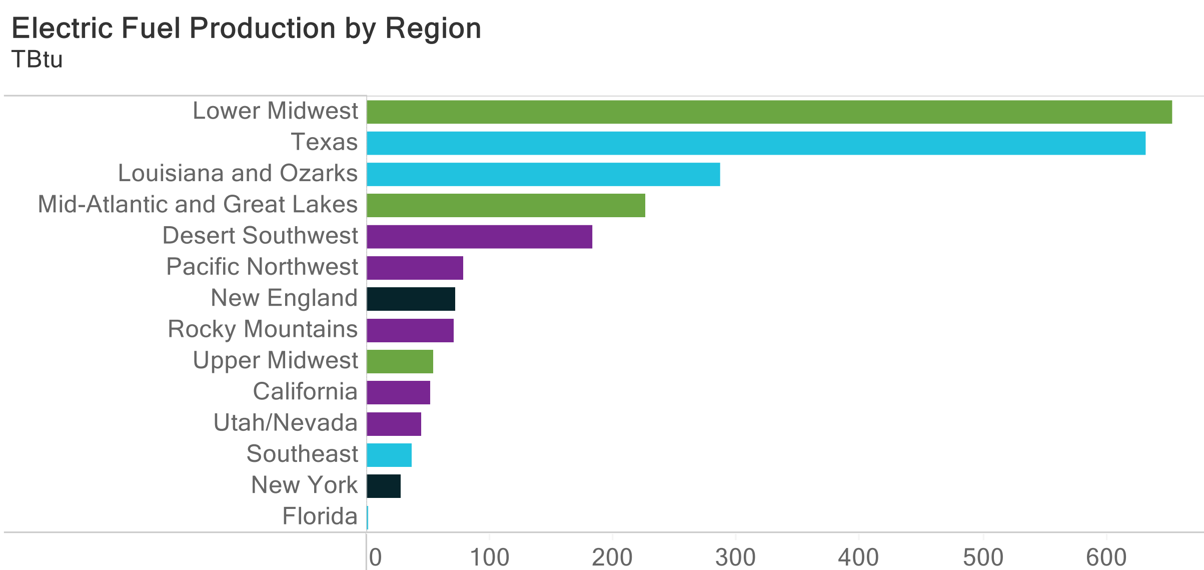
The quantity and type of low carbon fuels produced across the U.S. reflects diverse regional resource endowments. Similar to carbon management outcomes, regional differences are primarily explained by the cost and potential of biomass, renewables and geologic sequestration.

In general, regions follow one of the following infrastructure trajectories to support low carbon fuel production and net-zero emissions: (1) the development of a biofuels industry where bio-refineries are equipped with carbon capture (i.e., BECCUS) and $CO_2$ is sequestered to provide negative emissions; or (2) the development of a synthetic electric fuels industry via the production of low-cost electrolytic hydrogen and utilization of captured $CO_2$. The primary exception to these trajectories occurs in regions without geologic sequestration availability where $CO_2$ captured from bio-refineries is utilized instead of sequestered, such as the Northeast.

Production of biofuels is concentrated in regions with significant biomass feedstocks and nearly two-thirds of national production occurs in the Southeast, Midwest and Mid-Atlantic (Figure 13). Most of the remaining production occurs in regions along the Gulf Coast where geologic sequestration is plentiful, while feedstock potential limits production in the Northeast and West. Synthetic electric fuel production primarily occurs in regions across the Great Plains. High-quality onshore wind resources stretching from Texas to Wyoming provide clean electricity to electrolysis facilities producing low-cost hydrogen, a major cost component of electric fuels (along with captured $CO_2$). Electric fuel production is also dispersed across regions of the Western U.S. due to low-cost solar and wind, but limits on the supply of low-cost captured $CO_2$ (e.g., biomass feedstock availability) constrain production. DAC is available but remains a high-cost source of CO2 through the study period.

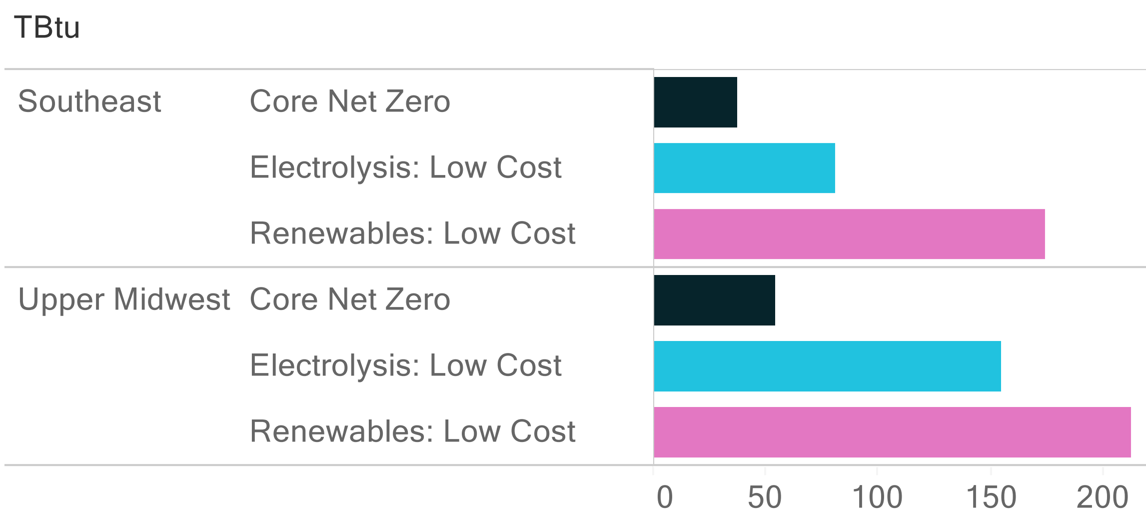
### Figure 13 Regional Synthetic Fuel Production: Core Net Zero (2050)




The regional patterns of synthetic bio- and electric-fuel production are broadly consistent across the uncertainties considered in this paper, and production rises and falls in the concentrated regions in response to economic and emissions target signals. For example, biofuels production in the Southeast and Mid-Atlantic increases with lower (relative to baseline) feedstock costs and falls with higher feedstock costs. Similarly, synthetic electric fuels from the Lower Midwest increase with a more stringent E&I $CO_2$ target and decreases with a relaxed target. An exception to this dynamic occurs when renewable or electrolysis costs further decrease below baseline levels, because low-cost electrolytic hydrogen production is available in nearly all regions (Figure 14). Electric fuel production is unlocked in regions that primarily produce biofuels in the CNZ scenario (e.g., Southeast and Upper Midwest). The availability of $CO_2$ for fuel synthesis is not constraining, because: (a) captured carbon in these regions is re-directed away from geologic sequestration; and (b) direct air capture is available in all regions and lower-cost renewables improve their economics.

**Figure 14 Regional Electric Fuel Production (2050)**



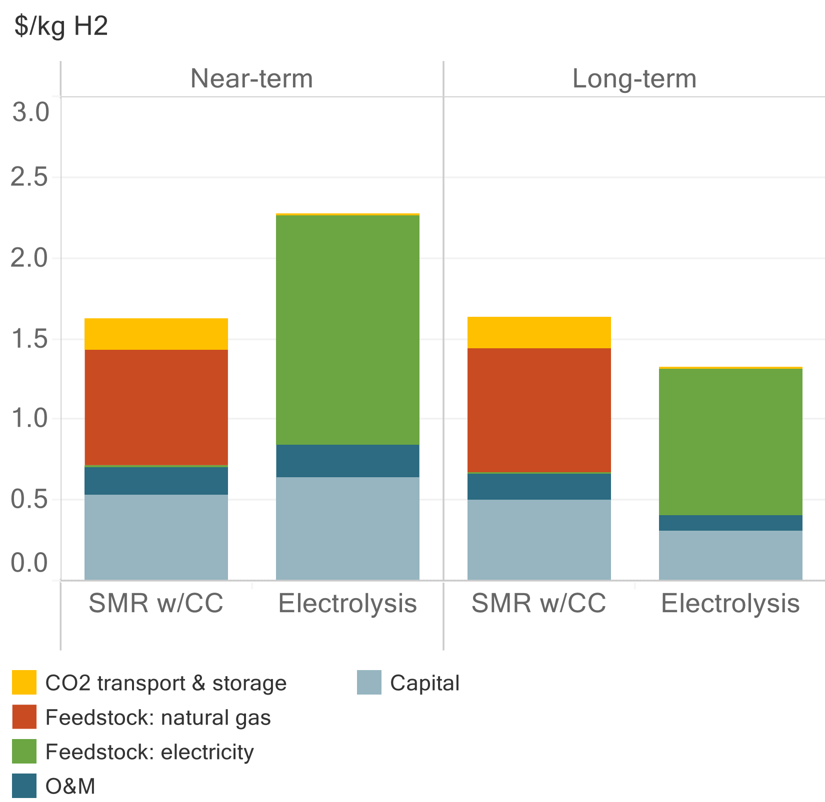

# Fuel Cost Decomposition

In this section, we provide indicative cost estimates for low carbon fuels, including production cost components, as well as delivery costs. We use these estimates to explain: (a) the relative contribution of different components towards the total delivered cost of a given fuel; (b) the competitiveness of alternative technology options; and (c) the cost premium of a low carbon fuel relative to its fossil fuel equivalent.

## Green and Blue Hydrogen Production Costs

Figure 15 compares production costs for blue and green hydrogen in the near-term (2030) and long-term (2050). Approximately 60% of blue hydrogen's production costs come from pipeline gas consumption and $CO_2$ transportation & storage, while capital and operations and maintenance (O&M) constitute the remainder. Total blue hydrogen production costs remain near $1.6/kg across the near- and long-term due to relatively flat growth in the cost of natural gas and no assumed technological learning (CO2 storage costs may increase in regions with growing competition from other sources of captured $CO_2$). Green hydrogen produced from electrolysis decreases from approximately $2.3/kg in 2030 to $1.3/kg in 2050. Electricity costs are the largest component of electrolytic hydrogen production (approximately two-thirds), so production cost targets should consider innovation in renewable electricity generation technologies together with improved electrolysis cost and efficiency. This is particularly important to reach any near-term cost targets (e.g., $1/kg by 2030) or technology competitiveness, because green hydrogen is about 40% more expensive than blue hydrogen in 2030 at an electricity cost of $30/MWh.

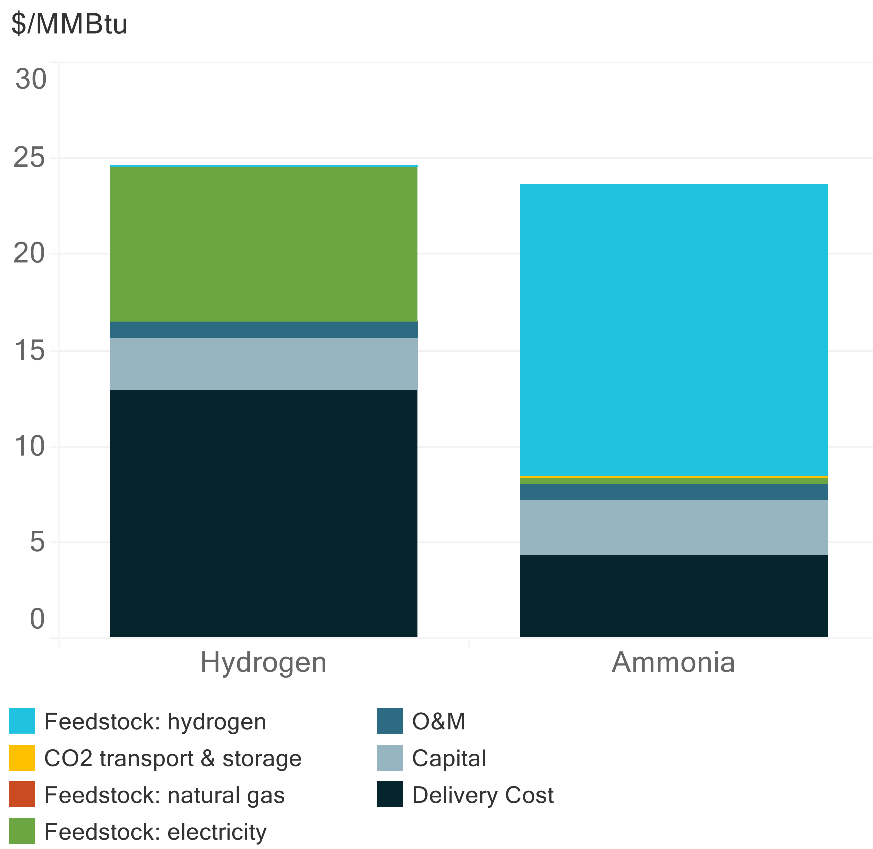
**Figure 15 Hydrogen Production Costs**



## Hydrogen versus Ammonia

Hydrogen and ammonia are promising avenues to decarbonize long-distance transportation applications where electrification may be prohibitively expensive or impractical. The competitiveness of directly using hydrogen strongly depends on its delivery costs (i.e., cost of transport, distribution and refueling). For example, a delivery cost of $1.5/gge would represent half of hydrogen's total delivered cost (Figure 16). In contrast, ammonia is expected to have lower delivery costs and a higher share of production costs that are driven by hydrogen feedstock costs. An ammonia delivery cost of $0.5/gge, similar to today's cost of distributing liquid fossil fuels, results in a nearly equal total delivered costs for both fuels. All else equal, lower hydrogen production costs improve the competitiveness of ammonia, whereas lower hydrogen delivery costs improve the competitiveness of direct hydrogen use. The costs below do not account for additional non-fuel costs, such as adapting existing ships.

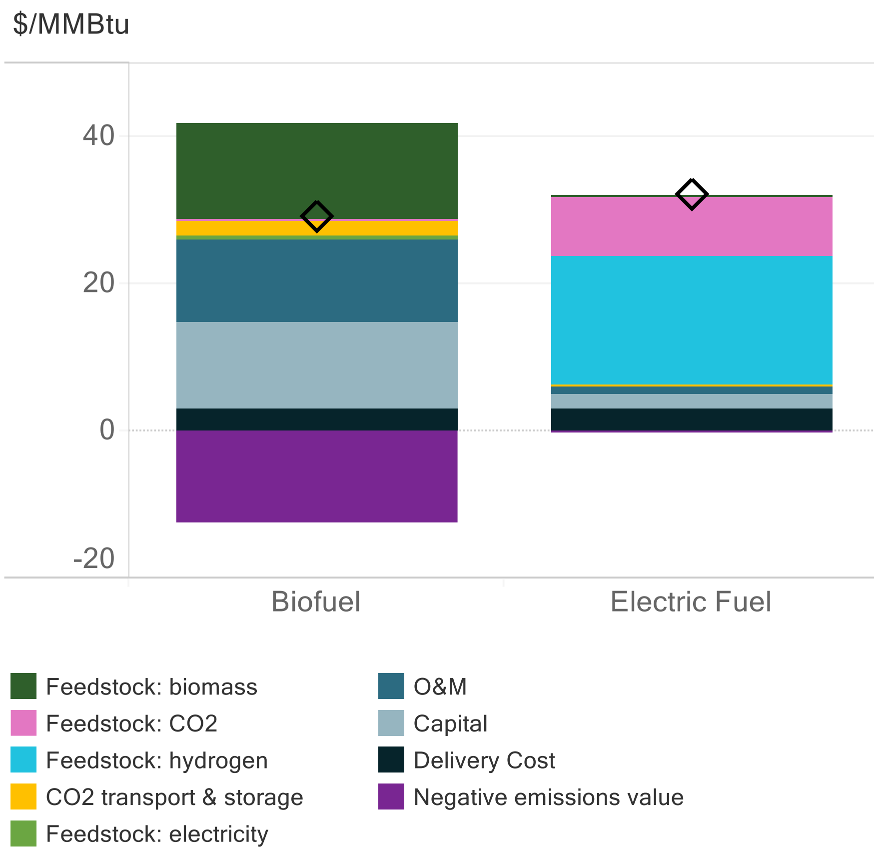
**Figure 16 Hydrogen-based Fuels: Total Delivered Cost (2050)**



## Synthetic Liquid Fuels

As shown in Figure 17, biomass- and electricity-derived synthetic liquid fuels have similar total production costs, but the contribution from components varies significantly. For synthetic biofuels, capital and O&M costs constitute a significant portion of gross production costs (60%), while biomass feedstocks account for about one-third. Bio-refineries equipped with carbon capture (i.e., BECCUS) provide negative emissions and the value of this commodity is significant in 2050 when net-zero emissions are binding. The net cost of biofuels (shown in the diamond) is below $30/MMBtu because of the negative emissions value. Synthetic electric fuels are characterized by very high feedstock costs, with hydrogen and $CO_2$ feedstocks representing approximately 60% and 30% of production costs, respectively. For both types of synthetic fuels, delivery costs are low (~$3/MMBtu, or 10% of total delivered costs) relative to production costs since these "drop-in" fuels can utilize existing energy infrastructure.

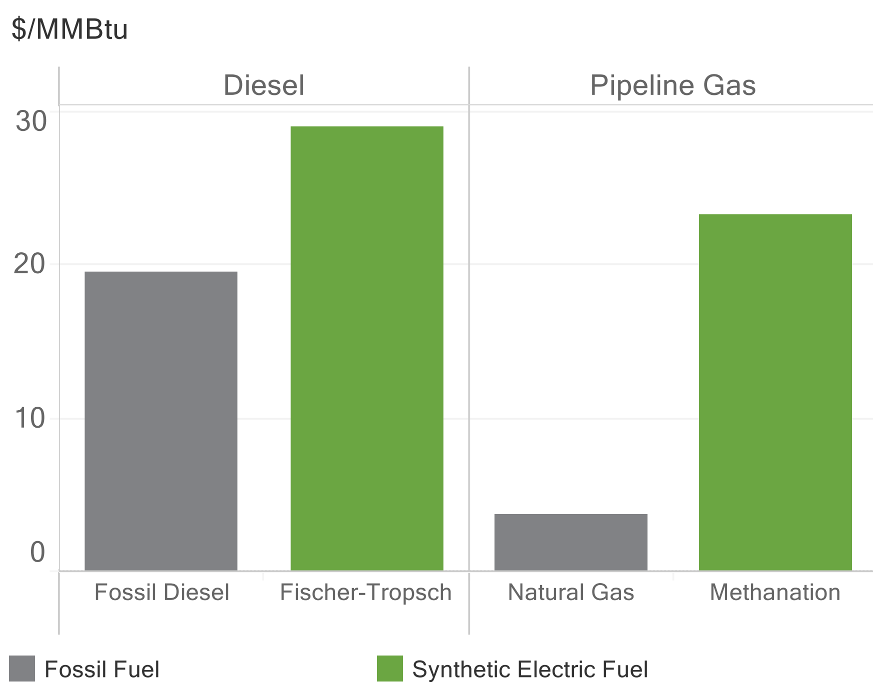
**Figure 17 Synthetic liquid fuels: total delivered cost (2050)**



## Low carbon fuel cost premium

One of the key findings of low carbon fuel production to support net-zero emissions is the prioritization on displacing liquid fossil fuels rather than gaseous fossil fuels (e.g., natural gas). This is primarily the result of a smaller cost difference between low carbon and fossil liquid fuels. To illustrate this point, we compare production costs in 2050 for fossil diesel and natural gas against their synthetic electric fuel counterparts in Figure 18. The cost premium of low carbon diesel is below $10/MMBtu, whereas the cost premium of low carbon pipeline gas is nearly $20/MMBtu. The difference in cost premiums is further exacerbated by differences in the emissions intensities of the displaced fossil fuels, where diesel is about 40% more carbon-intensive than natural gas. Dividing the cost premium by the avoided emissions factor results in a $ per $tCO_2$ avoided of approximately $130/$tCO_2$ for diesel fuel and $370/$tCO_2$ for pipeline gas. This dynamic explains why biomass and utilized CO2 are allocated to low carbon fuel production to displace refined liquid fuels, whereas natural gas and liquefied petroleum gas represent nearly all remaining gross energy $CO_2$ emissions in 2050.

**Figure 18 Comparison of Fossil and Synthetic Electric Fuels: 2050**



# Impacts from Achieving DOE's Hydrogen Shot

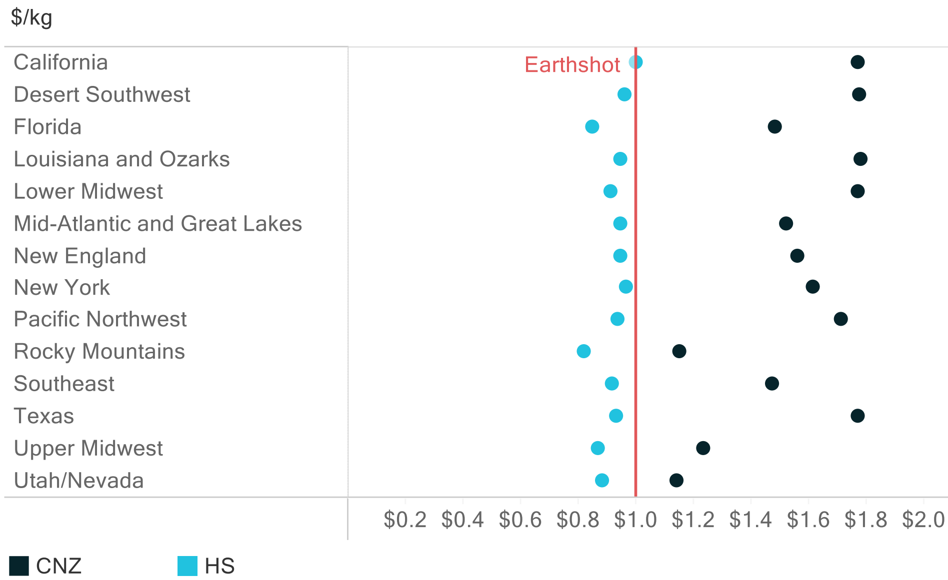
In June 2021, the U.S. DOE announced the Hydrogen Shot, its first Energy Earthshot, with a goal of reducing clean hydrogen's production cost by 80% to $1/kg by 2030.[9] This represents a significant cost reduction from today's clean hydrogen production cost ($5/kg per DOE) and baseline projected costs for 2030 (above $2/kg), which already reflect cost and performance improvements for clean energy technologies.

In order to understand the implications of this goal for low carbon fuels, we modeled a Hydrogen Shot (HS) scenario where the DOE's 2030 cost target is achieved. For the purposes of this case study, we assume the target applies to hydrogen production from electrolysis and that the following two changes from the CNZ scenario were made to realize $1/kg by 2030. First, we assume electrolysis achieves a capital cost of $100/kW-e and 75% efficiency in 2030 and thereafter. Second, we used the low-cost projections for renewable electricity generation technologies and further accelerated their achievement by one decade. In other words, the cost and performance levels achieved by 2040 in NREL's ATB 2020 *Advanced Technology Innovation* scenario are alternatively realized by 2030.

As a result of the aggressive electrolysis and renewable technology trajectories, all regions across the U.S. produce electrolytic hydrogen at a cost at or below $1.0/kg by 2030 (Figure 19). Relative to the CNZ scenario, this is a 40%-50% cost reduction. Cost reductions persist after 2030 and electrolytic hydrogen production costs range from $0.6 to $0.9/kg by 2050 across all regions (costs range from $1.1 to $1.7/kg in the CNZ scenario).

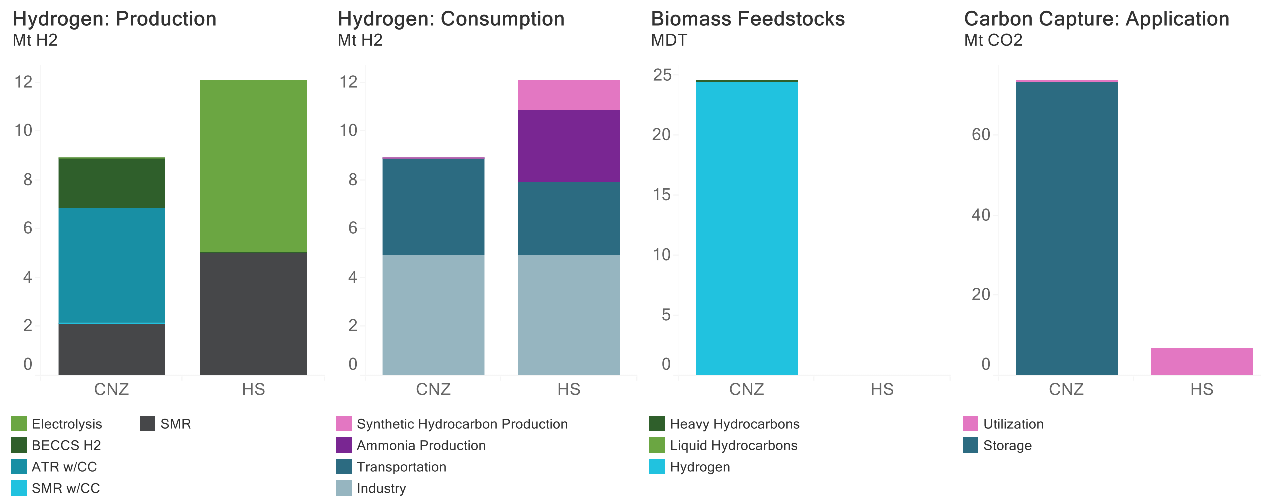
[9] https://www.energy.gov/eere/fuelcells/hydrogen-shot

## Figure 19 Regional Electrolytic Hydrogen Production Costs: 2030



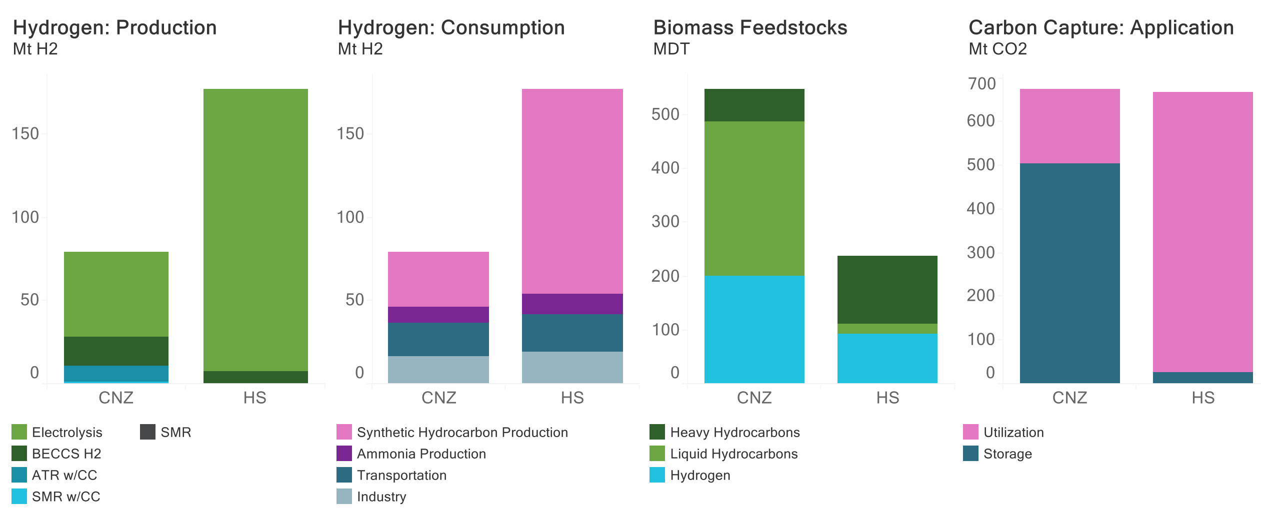

The cost reductions have implications across the energy system in the near-term (2030) when the Hydrogen Shot target is achieved, as well as the long-term (2050). Figure 20 and Figure 21 illustrate these broad dynamics by comparing metrics for the HS and CNZ scenarios, including hydrogen production, hydrogen consumption, biomass feedstock consumption and captured carbon applications. In the near-term, hydrogen production increases by one-third, driven by demand from synthetic hydrocarbon and ammonia fuel production. Electrolytic hydrogen, which is negligible in the CNZ scenario, provides 60% of supply. The focus on synthetic fuel production directs all captured carbon towards utilization and avoids the need for biofuels to meet the 50% by 2030 GHG target.

**Figure 20 Energy System Metrics: 2030**




Long-term outcomes are more pronounced with hydrogen demand more than doubling and electrolysis represents nearly all production. Very low-cost electrolytic hydrogen facilitates more widespread use of synthetic electric fuels at the expense of biomass (down by more than 50%) and geologic sequestration (nearly zero). A decline in biofuels production with carbon capture results in direct air capture deployment (~300 MMT $CO_2$) to provide the negative emissions needed for $CO_2$ utilization. In summary, the impact of the Hydrogen Shot target, if achieved through electrolysis and renewable cost reductions, is a low carbon fuel economy dominated by synthetic electric fuels with lower demand for bioenergy and CCS to meet net-zero.

**Figure 21 Energy system metrics: 2050**



# Technical Appendix

Table 4 summarizes key assumptions from the CNZ scenario that are applied consistently across the analysis unless specified otherwise. These inputs are consistent with the *Carbon Management in Net-Zero Energy Systems* white paper.

**Table 4 Key Base Assumptions**

| Category | Assumption |
|---|---|
| **Emissions Targets** | -Net GHG: 50% below 2005 levels by 2030 and net-zero by 2050<br>-Net E&I $CO_2$: limited to 3.2 $GtCO_2$ in 2030 and 0.0 $GtCO_2$ in 2050 |
| **End-Uses** | -Demand for energy services are consistent AEO 2021<br>-Energy efficiency and fuel switching to electricity and hydrogen-based fuels is generally consistent with the Central scenario from *Carbon-Neutral Pathways for the United States* (Williams et al., 2020) |
| **Fossil Fuel Prices** | -Cost projections are from the AEO 2021 Reference Case<br>-Natural gas is $3.7/MMBtu by 2050 and liquid fuels are approximately $20.0/MMBtu |
| **Geologic Sequestration** | -Storage potential is from Princeton University's Net-Zero America Project (NZAP) study (1.9 $GtCO_2$ of annual injection)<br>-Cost of transportation and storage is derived from NZAP and excludes near-term EOR benefits |
| **Biomass** | -Feedstock costs and potential are derived from DOE Billion-Ton Study (BTS)<br>-BTS feedstock potential is modified to include 50% of herbaceous energy crops, resulting in approximately 750 million tons of total biomass |
| **Renewables** | -Cost and performance trajectories are from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) 2020 Moderate Scenario<br>-Resource potential for wind and solar resources is derived from NREL's Regional Energy Deployment System (ReEDS) 2020 Reference Access siting regime assumption. We assume 75% of available potential for onshore and offshore wind potential (5.9 TW and 3.7 TW, respectively). Utility-scale solar deployment is further constrained up to 1.5% of available land area in each region (3.7 TW across the contiguous U.S.). |
| **Electrolysis** | -Assumed capital cost of $250/kW-e and efficiency of 72.5% by 2050 |
| **Direct Air Capture** | -Cost & performance is derived from Larsen et al. (2019) mid-range values<br>-Indicative levelized cost of capture (excludes transport and storage) is $110 per metric ton in 2050 |

Electrolyzer cost estimates vary and their long-term trajectory is uncertain. We developed capital cost estimates for the near-term (2020), medium-term (2030) and long-term (2050) based on a review of the literature, as shown in the table below.

**Table 5 Electrolyzer Capital Cost Estimates (2020$/kW-e)**

| Source | 2019 | 2020 | 2030 | 2050 |
|---|---|---|---|---|
| **Bloomberg NEF (2020)** | $1,400 | | $440 - $1,008 | $95 - $217 |
| **IEA (2019)** | | $900 | $700 | $450 |
| **IRENA (2020)** | | $650 - $1,000 | | $130 - $307 |
| **EER** | | **$900** | **$500** | **$250** |

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